CITY OF CHULA VISTA
MUNICIPAL ENERGY UTILITY
FEASIBILITY ANALYSIS

REPORT

Submitted Jointly by:

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INTRODUCTION

I. INTRODUCTION

The purpose of this section of the Report is to provide information on the background for this Report, a review of previous City activities, and a discussion of the format of the remainder of this Report.

A. Background

On April 15, 2003, the City Council for the City of Chula Vista (Chula Vista or City) authorized the retention of the team of Duncan, Weinberg, Genzer & Pembroke, P.C. (Duncan), McCarthy & Berlin, L.L.C., and Navigant Consulting Inc. (NCI) (collectively the Municipal Electric Utility (MEU) Study Team) to undertake the financial, legal and technical feasibility of various possible municipal energy business structures and alternatives. Specifically, the MEU Study Team was retained to perform what the City had described as its Municipal Electric Utility Feasibility Analysis, to answer the questions: *Is it desirable for the City to pursue the implementation of an MEU? If so, what form of MEU?*

In an effort to assist the City, the MEU Study Team submitted a proposal that included a multi-disciplinary methodology to address these two critical questions, as well as addressing the following requests from the City:

1. Consider and incorporate, if appropriate, previous City actions and analysis contained in the City's adopted Energy Strategy and Action Plan.
2. Identify the characteristics of Chula Vista that present opportunities or challenges to MEU implementation.
3. Describe the various forms of MEUs; give California examples where possible. Identify the risks/benefits, pros/cons of each.
4. Describe step-by-step, the MEU formation and implementation process. Include a timeline. Include descriptions of any required approvals from the CPUC, FERC, or other governmental agencies.
5. Estimate and describe the financial and human capital resources required for each stage of municipalization.
6. Estimate and describe the costs, risks, potential environmental impacts and vulnerabilities of MEU formation and implementation. How can costs be managed and risks mitigated?
7. Describe the current legal, regulatory, political, and economic framework in which an MEU would operate, the challenges and opportunities presented thereby, and approaches to overcoming and taking advantage of such challenges and opportunities.
8. Describe the potential benefits of MEU operation in Chula Vista: In what specific ways could a Chula Vista MEU deliver benefits not currently provided by SDG&E?

9. Provide case studies, which illustrate both the potential benefits and pitfalls of an MEU.
10. Identify alternatives/lower risk approaches to MEU implementation including but not limited to aggregation (e.g. types of partnerships with SDG&E or regional partnerships). Identify the risks/benefits, pros/cons of each. In completing this section consider alternatives contained in the City's existing Energy Strategy and Action Plan.
11. If justified by the analysis, recommend an initial MEU business model that would implement City's energy objectives. Provide a proposed outline of a Focused Feasibility Study and Implementation Plan for the recommended MEU.

The starting point for this feasibility analysis was to review previous activity undertaken by the City, including the previously adopted "City of Chula Vista Energy Strategy and Action Plan."

B. City Energy Strategy

On May 29, 2001, the City Council passed Resolution No. 2001-162 adopting the City's Energy Strategy and Action Plan (City Energy Strategy). The City Energy Strategy marked the culmination of an assessment of the City's energy management options, which was prepared by MRW and Associates. As Task No. 1 of the MEU Analysis, the MEU Study Team reviewed the MRW report, the City's Energy Strategy and the Energy Strategy Status Update provided by the City.

1. Overview of City's Energy Strategy

The MRW Report (and City Staff) developed a portfolio of twelve options for the City to consider. The options were grouped into "highly recommended," "promising," and "higher risk" strategies. The highly recommended strategies were deemed to have low or manageable risk and have the potential for short-term payoffs. These included:

1. Continue and expand energy conservation projects in existing and future City facilities;
2. Continue, expand, and promote energy efficiency and renewable energy programs for businesses and residents;
3. Monitor the development of the California electric energy market and prepare for the opportunity to enter into competitive supply contracts with energy service providers to serve City electric loads;
4. Develop and implement a legislative strategy to support the City's Energy Strategy; and
5. Continue and expand efforts to implement CO_2 Reduction Plan and a GreenStar Building Incentive Program.

The "promising options" were deemed to offer significant benefits; however, additional risk with a payoff over several years was included as well. These options consisted of:

6. Pursuit of distributed generation opportunities within the City;
7. Look for opportunities to enter into a bilateral agreement with a power generator;[1]
8. Partner with a third-party to build and operate generation facilities; and
9. Develop an emission offsets program based on mobile sources.

Finally, three "higher-risk options" were identified. These were deemed to require large capital outlays, carry significant risk, and require a longer timeframe for payoff. These options include:

10. Finance, own, and operate a large-scale power plant;
11. Form a municipal distribution utility (for all or a portion of the City); and
12. Become a municipal aggregator.

Resolution No. 2001-162 adopted the City's energy strategy and eight (8) options for the City to begin or continue. The City has been pursuing options 1, 2, 5 6 and 7 above.

The MEU Study Team is also informed that the City has held discussions with the San Diego Port Authority (Port Authority) and Duke Energy North America (Duke) regarding the potential relocation and repowering of the South Bay Power Plant (South Bay).

Finally, on June 5, 2001, the City also passed Ordinance No. 2835 establishing the City as a municipal utility.

2. Energy Strategy Discussion

The City has been involved in investigating its options following the failed California energy "experiment" for well over two years. The City Staff is sophisticated regarding the causes of the crises and several factors that continue to leave the state and the San Diego region in a precarious position regarding long-term reliable supply of energy.

The City has adopted an Energy Strategy that provides for the City to do essentially everything that a "typical" city can do to address citywide energy conservation,

1 "Bilateral contract" is a term referring to a transaction in the deregulated electric energy market meaning a contract between a generation supplier and end-use consumer that circumvents or bypasses a functioning commodity pool, such as the now defunct California Power Exchange. All retail competition, bilateral or other, characterized by direct transactions between end-use consumers and suppliers other than jurisdictional public utilities was suspended by the CPUC on September 20, 2001. Hence, strategy 3 referenced above and strategy 7, are identical and not available to the City until retail completion is reintroduced into California electric energy markets.

energy education, and environmental stewardship. In addition, the City has undertaken additional steps of pursuing distributed generation opportunities at City facilities (e.g. new police station). All of these efforts should continue as the City moves further into the energy field.

The City is now embarking on a more aggressive energy track, which may become the City's new energy program, one that goes beyond what the "typical" city is currently undertaking. This strategy includes: (1) the focused re-negotiation of the electric and natural gas franchise agreements with SDG&E; (2) exploring options for City acquisition of the electric output from the existing and proposed expansion of the methanol plant to serve the new City corporation yard and possibly other entities; (3) "Greenfield" municipal electric and natural gas services provided to new development areas within the City (exercising the City's right to provide utility services but avoiding condemnation of existing SDG&E distribution facilities); (4) discussions with the Port Authority and Duke regarding the South Bay Power Plant; and (5) conducting this MEU feasibility analysis.

The MEU Study Team commends the City on the efforts undertaken to date and the successes that the City has enjoyed. Regardless of the outcome of the ongoing negotiations with SDG&E and all of the other activities discussed as the new "track," the MEU Study Team believes that the City should continue with the work begun in the Spring of 2001 with the adoption of the City's Energy Strategy through the implementation of the MEU options recommended herein.

3. Incorporation of the City's Energy Strategy Into the Feasibility Analysis

The following strategies identified in the City's Energy Strategy are incorporated into this feasibility analysis.

Power Supply

- Identify renewable resource funding options;
- Partner with third parties to build and operate generation facilities; and
- Finance, own, and operate a large-scale power plant to meet a portion of the City's demand for electricity.

Power Supply and Regulatory Issues

- Monitor market and legal restrictions and be prepared to enter into an electric service contract with competitive suppliers (ESPs/generators).

Municipalization Alternatives

- Become a municipal aggregator and acquire energy, at negotiated rates, for City loads as well as all residents and businesses located with the City's jurisdiction.

Evaluate Distribution Utility Options

- From a baseline of the existing utility service provided by SDG&E, assess the overall strengths and weaknesses of options to own and operate all or portions of the local distribution system.

The main focus of this Report is to move beyond the current Energy Strategy and explore the other options and opportunities as well as the challenges that the City retained the MEU Study Team to identify and explore. One option will be the status quo, which would be to continue with the implementation of the current Energy Strategy and remain with SDG&E as the full service utility provided electricity and natural gas to all loads within the City. The other options are discussed in greater detail throughout the body of this report.

C. Existing Utility Franchise with San Diego Gas & Electric Company

San Diego Gas & Electric Company ("SDG&E") owns and operates both the electric and gas distribution systems in the City of Chula Vista under franchises granted by the Chula Vista City Council. The original twenty-five year franchise, granted in 1972 to operate the electric distribution systems in Chula Vista, expired in 1997 and was extended for a five year period under Ordinance No. 2746, adopted in 1998. The original franchise to operate a gas distribution system in Chula Vista, also with a 25 year term, expired in 1997 and was extended for a five year period pursuant to Ordinance No. 2747, adopted in 1998. Both the Electric and Gas Franchises expired, by their terms, on June 30, 2003.

Representatives of Chula Vista and SDG&E conducted negotiations respecting the renewal or extension of the Electric and Gas Franchises earlier this year. The terms of the proposals submitted by SDG&E for a fifty-five (55) year extension of the franchises were evaluated by the Chula Vista Staff and rejected as unacceptable. Once negotiations reached an impasse in late July 2003, the City and SDG&E attempted to agree on a temporary extension of the franchises to give the City more time to evaluate its options. The City offered a 90 day extension of the franchise agreements while SDG&E offered to extend service under current terms and conditions for a 45 day period. At this writing, the term of the franchises has not been agreed upon and the parties have continued to perform under the terms and conditions of current franchise agreements on a month-to-month basis.

The current franchise agreements have been an important element in the conduct of this feasibility analysis inasmuch as the terms, conditions and rates for gas and electric service as provided in the current franchises, or rate schedules promulgated thereunder, have provided the benchmark against which all of the MEU options have been measured to determine the feasibility of each of the MEU options analyzed by the MEU Study Team. In evaluating each of the MEU alternatives, the impact on franchise fee revenue received by the City under the current franchise agreements has been calculated and explicitly set forth as a cost of pursuing each MEU option. The MEU Study Team's test for economic feasibility of any and all MEU options requires that financial benefits of a particular option must exceed any foregone franchise fee revenue that would result from the pursuit of the MEU option.

D. Organization of the Report

The remainder of this Report is structured to provide the City with significant data and analysis to provide the City with the needed information to make an informed decision regarding potential next steps. The Report structure is also designed to cover all of the eleven Tasks requested by the City and they are incorporated into various sections and appendices to provide the reader with an opportunity to follow the flow of information and logic that concludes with the recommendations of the MEU Study Team.

Section II of this Report provides both an overview of the City's energy customers, projected load growth, an overview of the natural gas situation, and a discussion of the viability of City-owned generation.

Section III of the Report sets forth a description and discussion of the MEU options available for the City to consider. Specifically, Section III focuses on MEU opportunities including: municipalization under a Municipal Distribution Utility (MDU) format; "Greenfield" municipalization; community load aggregation (CCA) for both electricity services and natural gas services; and the creation of a Joint Powers Agency (JPA) or Municipal Utility District.

Section IV of the Report sets forth a detailed evaluation of each of the options considered by the MEU Study Team together with the basis for the recommendation made by the MEU Study Team and a roll out strategy for each option.

Section V of the Report contains the MEU Study Teams conclusions and recommendations.

Finally, the Report has four appendices: Appendix A is a list of abbreviations and acronyms and a glossary of terms; Appendix B discusses regulatory and legislative issues; Appendix C is a Technical Appendix which sets forth: (1) load forecasts, (2) financial pro forma and assumptions, (3) Natural Gas Regional Issues and Supply for power generation, (4) financing options, (5) implementation schedules, and (6) Operating and Maintenance Expense; Appendix D is a copy of SDG&E's Pro Forma Wholesale Distribution Tariff (WDAT).

The MEU Study Team is prepared to attend a public workshop before the City Council and the City Staff to discuss and explain the content of the Report and to respond to questions respecting the Report or the MEU Study Team' conclusions and recommendations.

SECTION II

CITY ENERGY CUSTOMERS,

PROJECTED ELECTRIC LOAD

AND

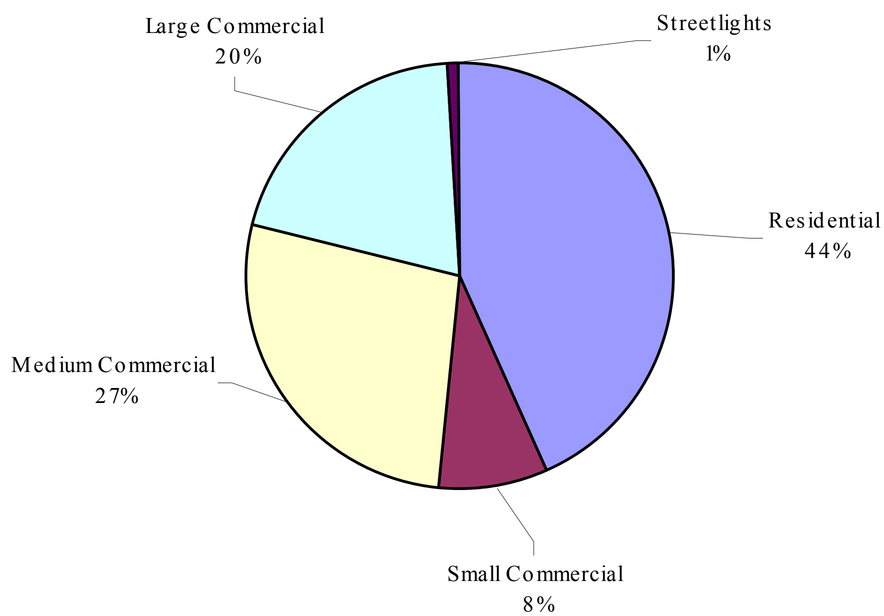
POWER SUPPLY

II. CITY ENERGY CUSTOMERS, PROJECTED ELECTRIC LOAD AND POWER SUPPLY

A. Summary

The chart below shows that City electric energy loads by customer sector for 2002 are consistent with the SDG&E system-wide average.

2002 Chula Vista Energy Use By Customer Class



However, the City is experiencing significant development in ways that will change this energy mix. Based on the City's general plan, growth is projected to occur in all customer segments, but especially in the medium commercial customer sector. The following table compares 2002 segment usage for the City and SDG&E[2] contrasted with forecast sector usage for Chula Vista in 2023.

[2] SDG&E 2002 FERC Form-1, page 301, line 2, column d, system wide results.

City Versus Regional Energy Usage

(MWh)

	Chula Vista 2002		SDG&E 2002		Chula Vista 2023	
Residential	305,735	44%	6,266,000	44%	568,772	42%
Small Commercial	56,216	8%	1,710,025	12%	78,154	6%
Medium Commercial	193,534	27%	3,391,622	24%	439,170	33%
Large Commercial	142,922	20%	2,725,159	19%	250,191	19%
Streetlights	6,627	0.9%	44,442	0.3%	8,745	0.7%
Total	705,034	100%	14,137,248	100%	1,345,032	100%

The City has been, and will continue to be, subject to strong growth in all energy using sectors. However redevelopment and new development are forecast to have the greatest impact in the medium sized commercial end-use consumer sector. In the next twenty years (see long-term load forecast below at 13-16) the City will experience growth in its overall energy requirements by more than 80% (2004-2023). As described in Section IV.F.3.d(1) at 120-21, a municipal distribution utility comprised of the City of Chula Vista electricity consumers projected for 2006 (recommended MEU implementation date) would be the 11th largest out of the state's 48 electric utilities based on customer count and the 20th largest based on energy sales.

B. Current and Future Electrical Loads

The MEU Study Team evaluated the existing customer base for the City's prospective MEU, and forecasted electric loads of residential customers; small, medium and large commercial and industrial customers; and street lighting electric demand. A 20-year load forecast includes sector growth rates and City general plan developments and is incorporated into financial projections for MEU structure options discussed in Sections III and IV. 2002 energy use statistics are applied to rate class static load profiles[3] to render sector-specific and Chula Vista-wide composite electric demand profiles. Analysis of rate class profiles reveals significant information about the City's electric loads. The following chart shows the annual hourly electric demand for Citywide loads during 2002.

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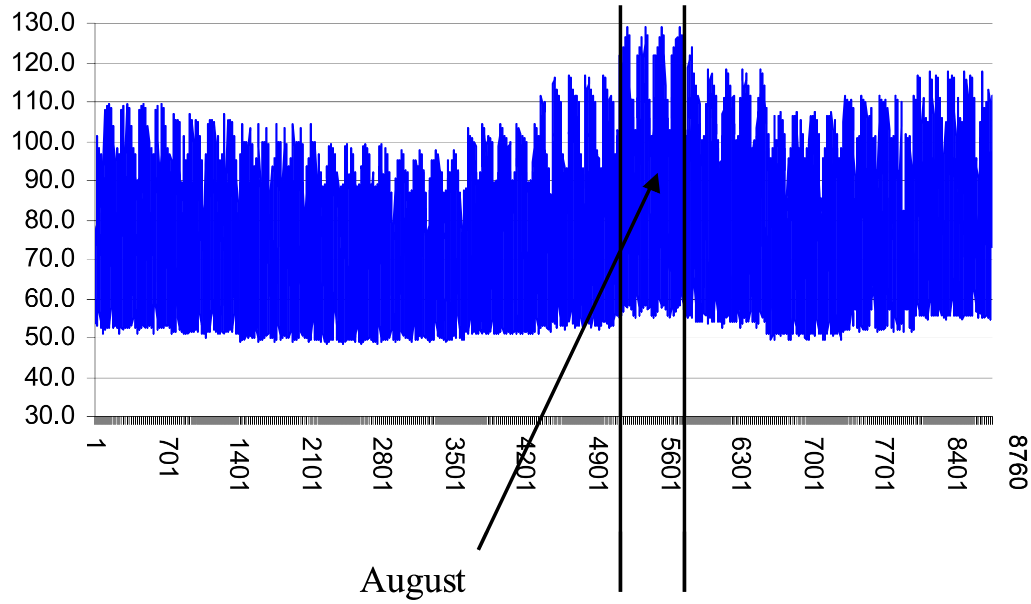
[3] Static Load Profiles were developed using three years of load research interval metering of SDG&E's different customer classes.

Chula Vista 2002
Hourly Electric Demand (MW)



Annual load factor, the ratio of peak annual demand (MW) to the annual average demand, is approximately 65 percent and is quite high when compared to other regions in the state. This is attributable largely to the area's mild climate and lower residential cooling electric load. Note that there are 8760 hours each year. The above graph represents each hour from 12:00 a.m. January 1 (hour 1) to 11:00 p.m. December 31 (hour 8760).

The following table lists the annual average load factors reflected in SDG&E's static load profiles, by customer class. The MEU Study Team applied these load profiles when modeling the City's prospective MEU customer loads.

SDG&E Static Load Profile Load Factors

Customer Sector	Load Factor
Large Commercial/Industrial	68.9%
Medium Commercial	60.8%
Small Comercial	48.1%
Residential	54.0%

1. Electricity Sector Load Shape

The residential class load, more so than the commercial or industrial classes, is greatly influenced by the climate. In hot, arid regions of the state, the residential load experiences large load "spikes" due to the load associated with residential (and to a much lesser degree small commercial) air conditioning.

The following table shows the climate variations that drive air conditioning electric loads measured in annual cooling degree-days for various cities in California.

Cooling Degree Days

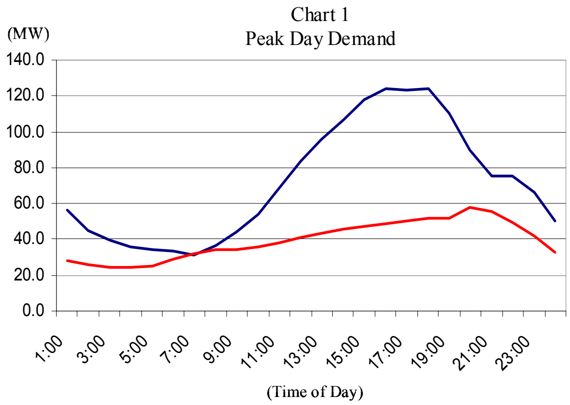
Chula Vista	Sacramento	Riverside	Bakersfield	Palm Springs
862	1,597	1,863	2,286	4,224

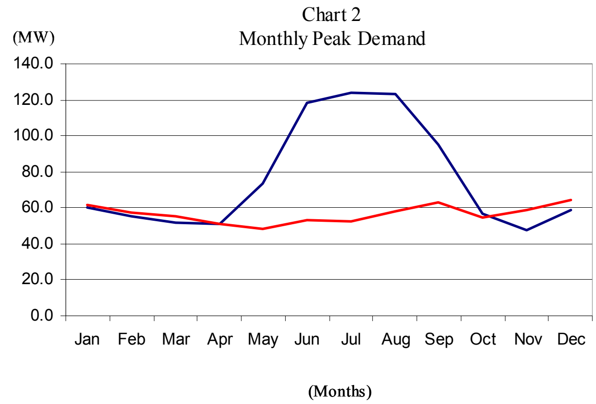
National Oceanic and Atmospheric Administration – Climatography of the U.S. Publication No. 81 30-Year Normals 1971-2000.CDD: Difference between the average daily temperature and a base temperature value (65 degrees F)

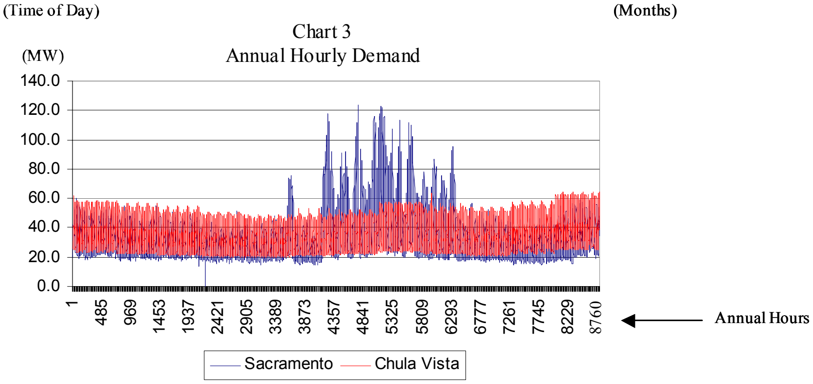
Compared to other Cities in California, the cooling degree-days are minimal in Chula Vista. This has a significant impact on residential and overall system load shapes and a direct bearing on the cost to serve the City's electric load. To illustrate the impact of low cooling degree-days, residential load shapes for Chula Vista and Sacramento are compared and contrasted below. When evaluating MEU energy requirements, it is important to recognize, not only how much energy is consumed, but also when the energy is consumed; i.e., the load shape. Charts 1 through 3 below apply the identical amount of energy – Chula Vista's residential energy consumption for 2002 – to city load shapes, for Sacramento and Chula Vista, to demonstrate sector climate sensitivity.

Comparison of Chula Vista and Sacramento

Electric Demand (MW)

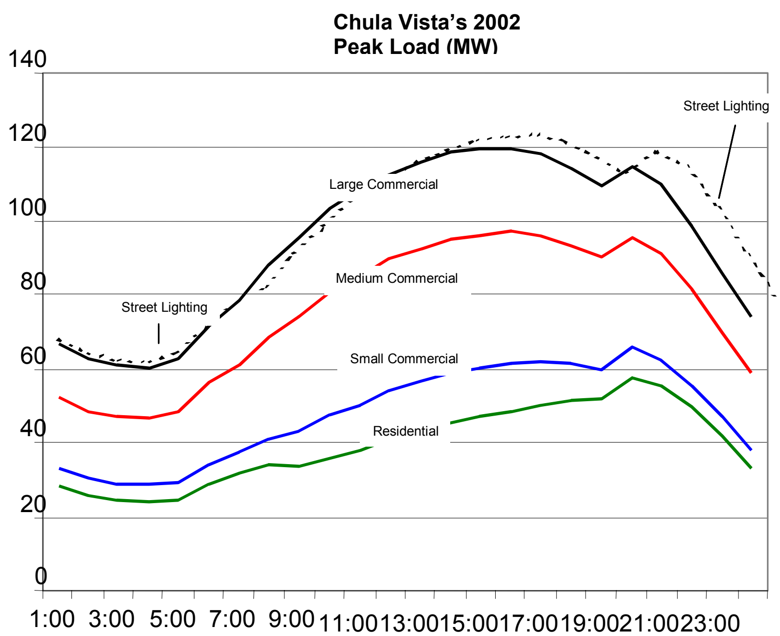






To satisfy the annual energy requirements of only Chula Vista's residential customers, the MEU would require a power plant with a capacity of 65 MW and operating annually at 54 percent of its capacity. To provide the identical amount of energy to residents of Sacramento, a power plant with 124 MW of capacity operating annually at 28 percent of its capacity would be required. Determination of the resulting cost-of-service implications requires analysis of specific plant capital costs, financing, and capacity and energy proportional cost allocation. However, the application of prototypical case values indicates the cost to serve Chula Vista residents is fourteen (14) percent less than the cost to serve the Sacramento residents the same amount of energy, based solely on a comparison of load shapes, and hence significantly less than the costs to serve the other cities shown in the above table. This feasibility analysis demonstrates that Chula Vista's residential loads are more economic to serve, attractive to generation suppliers, and render more types of generation projects cost-effective

Remaining sector load (commercial, industrial, and street lighting) characteristics tend to be less climate-dependent but do not dilute the overall favorable load shape. The following charts reflect the 24-hour peak demand profile and annual energy consumed by the five primary customer sectors.



(Load shapes reflect the City's existing customer loads)

2. Long-Term Electric Load Forecast

A 20-year electric load forecast for the residential sector is based on Household (HHD) projections contained in the San Diego Regional Planning Agency's (SANDAG) Preliminary 2030 Forecast of April 2003 and is tailored to incorporate City planning assumptions that generally accelerate growth expectations between 2003 and 2007. Associated growth rates are structured to resolve with the SANDAG projections in 2030. In addition to the overall growth in the number of HHDs, the forecast reflects the per capita increase in energy consumption from 1990 to 2000 of 15 percent or a compound annual growth rate of 1.4 percent.

Non-residential commercial loads are based on existing commercial loads escalated consistent with the projected growth in non-residential building stock through year 2020, trended through 2023. The MEU Study Team forecasts that over the 20-year planning horizon the City will experience a growth of approximately 22,000 customers, annual consumption growth of approximately 600 gigawatt-hours, and a peak load growth of approximately 100 MW. This growth represents a customer increase of 30 percent, and a demand and usage increase of over 80 percent. The chart below reflects maximum electric demand for a 20-year period (years 2004 through 2023).

20-Year Load Forecast 2004 - 2023

(Projected MEU Implementation 2006)

	Existing Service Area				Greenfield Service Area				Combined Service Areas			
	2004	**2006**	**2013**	**2023**	**2004**	**2006**	**2013**	**2023**	**2004**	**2006**	**2013**	**2023**
Sector Demand (MW)												
Residential	70	75	90	108	2	4	9	12	72	79	99	120
Commercial <20 kW	14	14	15	16	0	1	1	2	14	15	16	19
Commercial 20-500 kW	37	38	40	44	2	10	22	39	40	48	63	82
Commercial 500 kW +	24	25	26	29	0	2	3	13	25	27	29	41
Streetlight *	2	2	2	2					2	2	2	2
System Non-Coincident Peak	147	154	174	198	5	17	35	66	150	169	208	263
System Coincident Peak	126	131	148	170	4	16	33	63	130	147	181	233
Sector Energy (MWh)												
Residential	329,719	354,850	427,854	510,329	9,040	18,592	42,019	58,443	338,759	373,442	469,873	568,772
Commercial <20 kW	57,594	59,005	62,553	67,847	1,004	4,111	6,099	10,307	58,597	63,116	68,652	78,154
Commercial 20-500 kW	198,276	203,135	215,350	233,574	12,332	52,828	117,716	205,596	210,608	255,962	333,065	439,170
Commercial 500 kW +	146,424	150,012	159,032	172,491	3,012	12,333	18,298	77,700	149,436	162,345	177,330	250,191
Streetlight *	6,966	7,321	7,908	8,745	-	-	-	-	6,966	7,321	7,908	8,745
Total	738,978	774,323	872,697	992,986	25,387	87,863	184,132	352,045	764,365	862,186	1,056,829	1,345,032
Sector Customers												
Residential	67,587	70,734	77,340	80,219	1,853	3,706	7,596	9,291	69,440	74,440	84,935	89,510
Commercial <20 kW	3,148	3,225	3,419	3,709	55	225	333	563	3,203	3,450	3,753	4,272
Commercial 20-500 kW	320	328	347	377	20	85	190	332	340	413	537	708
Commercial 500 kW +	13	13	14	15	0	1	2	7	13	14	16	22
Total	71,068	74,300	81,121	84,320	1,928	4,017	8,120	10,193	72,996	78,317	89,241	94,513

* Projected Customer Populations Exclude the City's Streetlighting Service Accounts

To support the analysis of MEU structure options that include the City providing both energy commodity and distribution services to all City residents, the long-term load forecast is divided into two primary areas: (1) existing and planned development within areas currently served by SDG&E's distribution infrastructure, and (2) areas being developed in which SDG&E has not built distribution infrastructure and where the City may opt to build and operate same (Greenfield Developments or Greenfield Forecast).

To differentiate between potential Greenfield sites and other City development/redevelopment areas, the MEU Study Team interviewed City Planning Division Staff[4] to determine the most likely areas for Greenfield electric distribution system development. These consist primarily of the Mid-Bayfront, Otay Ranch and Sunbow planning areas.

a. Greenfield Area Load Forecast

The MEU Study Team evaluated the City's General Plan Land-Use Inventory through year 2020, wherein land-use is projected by square foot (sf^2) by activity type. Between 2002 and 2020, the City projects that its electric load service requirements will grow by 20 thousand households (HHD) and approximately 118 million sf^2 of non-residential development.

Electricity demand and energy requirements were modeled based on regional residential use and projected HHDs.

Non-residential growth is defined by the City Planning Division in fairly high-level "land-use definitions". The MEU Study Team evaluated these land-use definitions and interviewed City Staff to further understand likely development outcomes. Electric use "building type" profiles were assigned to each build-out area. Based on expected development, prototypical floor-area-ratios were applied to develop building area "footprints" or net building sf^2. Building type electric load profiles were modeled using the U.S. Department of Energy, Building Energy Simulation Modeling Program DOE-2.1.E (DOE-2). Assumptions for model inputs reflect minimum efficiencies to enable the modeled building to comply with California Energy Commission (CEC) Title-24 new construction building standards. Where DOE-2 model templates were not available to model a given building type, regional sampling of prototypical sites were applied.

In certain areas, as with land-use code 5002 (Regional Shopping Centers), for example, composite load profiles were assembled from several kinds of retail businesses for prototypical shopping centers based on surveys of more than 19,000 retail centers. The surveys reflect shopping center population patterns of small retail stores,

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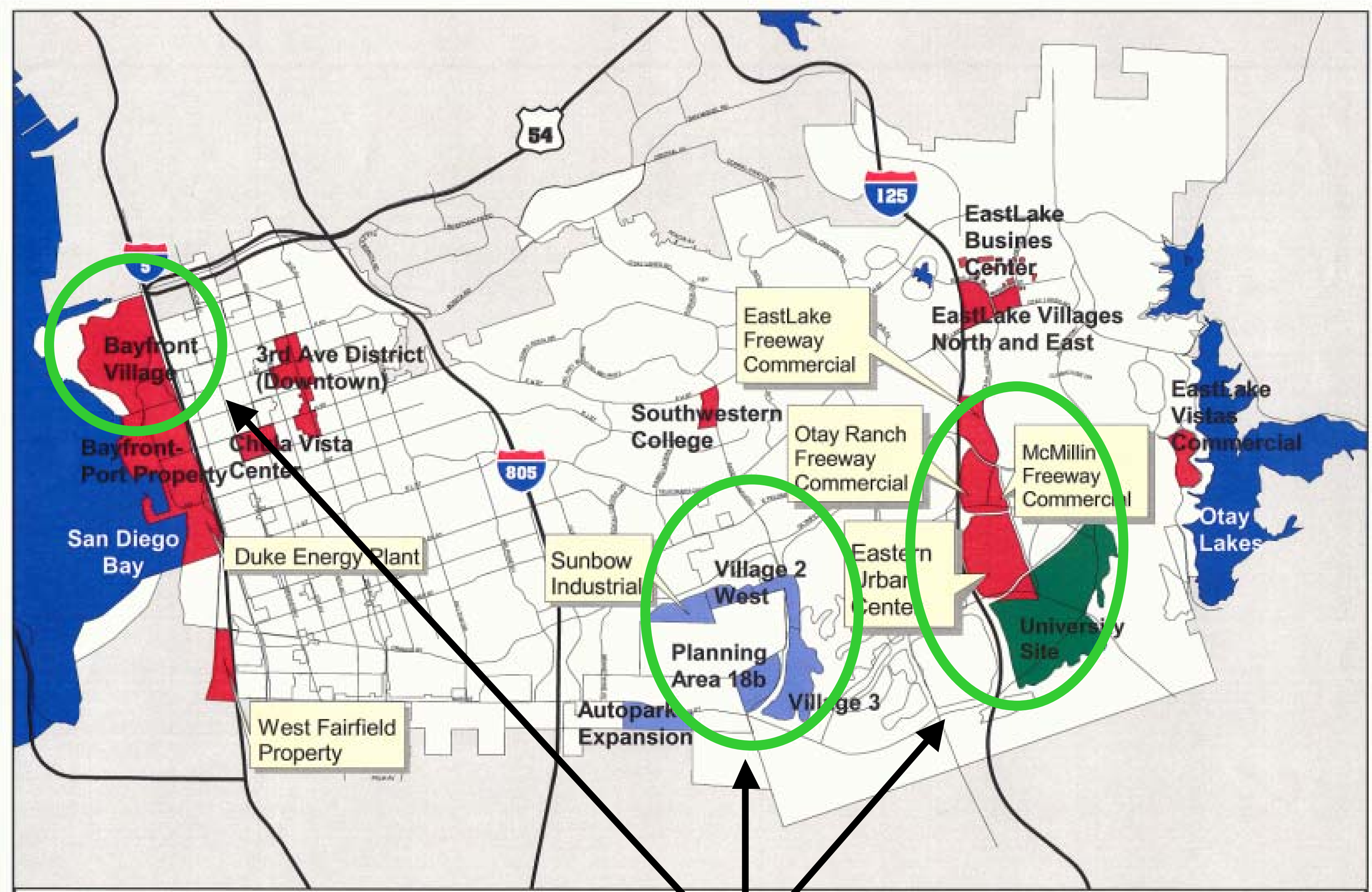
4 Mark Stephens, Principal Planner, Planning Division, City of Chula Vista.

fast food restaurants, full-menu restaurants, medium variety-type department stores, large retail stores, and grocery stores.

Given projected building type sf^2, modeled power densities (watts per sf^2) were applied to render building peak demand (kW). BT load factors were applied to peak demand to project annual energy requirements (kWh). Energy was allocated across 8,760 annual hours using rate class static load profiles rendering annual hourly average demand.

A map depicting the recommended Greenfield development areas is set forth below. Charts outlining (1) the breakdown of residential and non-residential load forecasts through 2020 for the recommended Greenfield areas; and (2) Greenfield land use inventory projections follow the map.

City Development and Redevelopment Areas



Greenfield Development Areas

GREENFIELD LAND USE INVENTORY PROJECTED THROUGH 2020

TAZ ZONE	Greenfield Arena	Use CODE	LAND USE	Residential Households	Building Type (BT)	Commercial FAR [4]	Building ft²	Power Density Watts/ft²	BT Non-Coincident Peak (kW)	Load Factor	2020 Non-Res. An kWh [4]	Res. Annual kWh [4]
3871	**MID-BAYFRONT**		RESIDENTIAL	1,000								5,980,060
3948	**OTAY RANCH**	5003	COMMUNITY COMMERCIAL		Retail Center	0.40	731,808	6.9	5,069.1	61.2%	27,166,600	
3949			RESIDENTIAL	750								4,485,045
3957		5002	REGIONAL COMMERCIAL		Retail Center	0.40	486,000	6.9	3,366.5	61.2%	18,041,573	
3982		6102	CHURCH		Church	0.30	105,851	4.0	423.4	12.1%	447,544	
3982		5003	COMMUNITY COMMERCIAL		Retail Center	0.40	325,829	6.9	2,257.0	61.2%	12,095,605	
3982		6806	ELEMENTARY SCHOOL		Schools	0.05	23,879	8.7	206.9	19.7%	357,789	
3982		6804	SENIOR HIGH SCHOOL		High Schools	0.10	217,800	8.7	1,886.8	17.7%	2,928,569	
3982			RESIDENTIAL	1,585								9,478,395
3995		6109	COMMUNITY PURPOSE FACILITY		Medium Office	0.40	144,619	8.2	1,185.9	48.1%	4,993,973	
3995		6806	ELEMENTARY SCHOOL		Schools	0.05	23,879	8.7	206.9	19.7%	357,789	
3995		6001	OFFICE HI RISE		Large Office	0.40	343,253	6.5	2,231.1	48.1%	9,395,802	
3995		6002	OFFICE-LOW RISE		Medium Office	0.25	686,070	8.2	5,625.8	48.1%	23,691,290	
3995		5002	REGIONAL COMMERCIAL		Retail Center	0.40	684,763	6.9	4,743.3	61.2%	25,420,176	
3995			RESIDENTIAL	2,332								13,945,499
3997		6109	COMMUNITY PURPOSE FACILITY		Medium Office	0.40	109,771	8.2	900.1	48.1%	3,790,606	
3997		6806	ELEMENTARY SCHOOL		Schools	0.05	23,879	8.7	206.9	19.7%	357,789	
3997		6805	JUNIOR HIGH OR MIDDLE SCHOOL		High Schools	0.10	108,900	8.7	943.4	17.7%	1,464,285	
3997		5004	NEIGHBORHOOD SHOPPING CENTER		Retail Center	0.40	125,453	6.9	869.0	61.2%	4,657,131	
3997		6804	SENIOR HIGH SCHOOL		High Schools	0.10	217,800	8.7	1,886.8	17.7%	2,928,569	
3997			RESIDENTIAL	1,501								8,976,070
4000		6801	UNIVERSITY (see note 2)		College	0.30	372,162	8.7	3,237.8	52.6%	14,914,416	
4024		6102	CHURCH		Church	0.30	31,363	4.0	125.5	12.1%	132,606	
4024		6806	ELEMENTARY SCHOOL		Schools	0.05	23,879	8.7	206.9	19.7%	357,789	
4024		5007	STREET FRONT COMMERCIAL		Retail Center	0.40	52,272	6.9	362.1	61.2%	1,940,471	
4024			RESIDENTIAL	291								1,740,197
4033		6801	UNIVERSITY (see note 2)		College	0.30	503,082	8.7	4,376.8	52.6%	20,161,055	
4037		6102	CHURCH		Church	0.30	78,408	4.0	313.6	12.1%	331,514	
4037		5003	COMMUNITY COMMERCIAL		Retail Center	0.40	233,482	6.9	1,617.3	61.2%	8,667,439	
4037		6806	ELEMENTARY SCHOOL		Schools	0.05	23,879	8.7	206.9	19.7%	357,789	
4037			RESIDENTIAL	1,457								8,712,947
4040		2103	LIGHT INDUSTRY - GENERAL		Industrial Assembly	0.25	2,100,681	7.9	16,595.4	40.4%	58,785,075	
4254		2103	LIGHT INDUSTRY - GENERAL		Industrial Assembly	0.25	362,637	7.9	2,864.8	40.4%	10,147,968	
4052			RESIDENTIAL	241								1,441,194
4254			RESIDENTIAL	134								801,328
4013	**SUNBOW**	2101	INDUSTRIAL PARK		Industrial Assembly	0.45	901,692	7.9	7,123.4	40.4%	25,232,785	
				9,291			9,043,093				279,123,998	55,560,735
									2023 Forecast		293,602,694	58,442,777

1. Parks are assumed to be no or minimal power consumers and no associated power is forecast.
2. College land-use at Traffic Analysis Zones (TAZ) 4000 and 4033 are one planned university - Electric load characteristics are based on a sample of eight regional universities.
3.Land reserved for dedications (roads and right-of-way easements) is estimated at 25% per City Planning staff - Floor Area Ratios (FAR) per prototypical building types.
4. City Planning Division provided a development forecast through 2020 - Related energy projections are escalated at 1.7% per year from 2020 through 2023
to reflected development additions, expansions and increases in energy intensity.

GREENFIELD LAND USE INVENTORY PROJECTED THROUGH 2020

ZONE	Greenfield Arena	CODE	LAND USE	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
3871	**MID-BAYFRONT**		**RESIDENTIAL**	19.9%	29.9%	39.9%	49.9%	58.2%	66.5%	74.8%	77.1%	79.4%	81.8%	84.1%	86.4%	88.7%	91.1%	93.4%	95.7%	98.0%	98.7%	99.3%	100.0%
3948	**OTAY RANCH**	5003	COMMUNITY COMMERCIAL	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3949			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
3957		5002	REGIONAL COMMERCIAL	18%	72%	77%	83%	88%	94%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3982		6102	CHURCH	0%	0%	0%	0%	0%	9%	37%	44%	52%	59%	67%	74%	79%	84%	90%	95%	100%	100%	100%	100%
3982		5003	COMMUNITY COMMERCIAL	0%	0%	0%	0%	0%	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3982		6806	ELEMENTARY SCHOOL	0%	0%	0%	0%	0%	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3982		6804	SENIOR HIGH SCHOOL	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3982			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
3995		6109	COMMUNITY PURPOSE FACILITY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%
3995		6806	ELEMENTARY SCHOOL	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3995		6001	OFFICE HI RISE	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3995		6002	OFFICE-LOW RISE	0%	0%	0%	0%	0%	8%	32%	45%	59%	73%	86%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3995		5002	REGIONAL COMMERCIAL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3995			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
3997		6109	COMMUNITY PURPOSE FACILITY	0%	0%	0%	0%	0%	19%	78%	82%	87%	91%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3997		6806	ELEMENTARY SCHOOL	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3997		6805	JUNIOR HIGH OR MIDDLE SCHOOL	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3997		5004	NEIGHBORHOOD SHOPPING CENTER	0%	0%	0%	0%	0%	12%	49%	59%	69%	79%	89%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3997		6804	SENIOR HIGH SCHOOL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3997			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
4000		6801	UNIVERSITY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	100%	100%	100%	100%
4024		6102	CHURCH	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4024		6806	ELEMENTARY SCHOOL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4024		5007	STREET FRONT COMMERCIAL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4024			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
4033		6801	UNIVERSITY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4037		6102	CHURCH	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4037		5003	COMMUNITY COMMERCIAL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	19%	75%	80%	85%	90%	95%	100%	100%	100%	100%
4037		6806	ELEMENTARY SCHOOL	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4037			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
4040		2103	LIGHT INDUSTRY - GENERAL	0%	0%	0%	0%	0%	4%	16%	22%	28%	34%	40%	47%	58%	69%	81%	92%	100%	100%	100%	100%
4254		2103	LIGHT INDUSTRY - GENERAL	0%	0%	0%	0%	0%	15%	60%	71%	82%	93%	104%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4052			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
4254			**RESIDENTIAL**	20%	30%	40%	50%	58%	66%	75%	77%	79%	82%	84%	86%	89%	91%	93%	96%	98%	99%	99%	100%
4013	**Sunbow**	2101	INDUSTRIAL PARK	25%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Notes: 1. Where multi-unit development is indicated (low-rise office, retail centers, etc) and development is planned abruptly in a given year, a 25% ramp up in development is assumed.
If a single building is feasible (schools, high-rise office, etc) no build-out ramp-up is assumed

C. Power Supply

In providing electric power to serve the City's customer base under any of the study options, the City has two basic choices: purchasing its electric power supply requirements from other utilities or generators participating in the California energy market (Contract Supply Strategy); or developing generation resources by constructing generation or participating with a generation developer and taking an equity interest in local generation (Generation Supply Strategy).

A key finding of this feasibility analysis, under any of the MEU structures analyzed, is that there is significant benefit to the City in electric generation ownership or ownership like rights. Furthermore, the City finds itself in unique circumstances, compared to other cities in the region, due to the confluence of natural gas and electric transmission facilities, and the location of the South Bay Power Plant (South Bay), and the location of the proposed Otay Mesa Power Plant (Otay Mesa), the City is geographically at the center of a significant portion of the energy facilities required to support the San Diego region. The MEU Study Team recommends that the City develop City-owned generation as the centerpiece of its MEU electric supply strategy. Our recommendation is not that the City should seek to develop a generation resource on its own; rather the MEU Study Team recommends that the City look to jointly develop and/or pursue a partial ownership with a developer in a larger base load generating unit.

1. In-City Generation

The Generation Supply Strategy, with in-City generation, provides the maximum opportunity for electricity cost savings achieved through the implementation of an MEU. Associated savings are positive in every year for both the CCA and MDU options. The combined CCA/Greenfield option with a Generation Supply Strategy offers the greatest benefits of all the options.

Ownership of generation would offer the City several advantages relative to procuring electricity through power purchase contracts (Contracts Supply Strategy). Among the benefits associated with participation in generation projects are:

- Lower electricity costs due to the City's retention of generation operating margins;
- The ability to leverage partial ownership to locate projects within the City and receive franchise fee revenues and local taxes; and
- Reduction in CAISO transmission charges, CAISO administrative charges, and protection against charges related to transmission system congestion.

The MEU Study Team modeled generation options for the City using operating and cost parameters of a new combined cycle gas turbine operating as a base load plant. These parameters include the unit's heat rate, capacity cost, variable O&M costs, availability factor, hours of planned operation, and the year the resource becomes operational. Sales of any excess production beyond what is needed to serve the City's load would be sold into the market. The price for excess sales reflects a 25% discount relative to the prevailing peak or off-peak price to reflect the probability that excess sales will occur in the lowest priced hours of the on- or off-peak periods.

The following assumptions were used in the calculation of generation costs:

Capacity:	130 MW
Technology:	Combined Cycle Natural Gas Turbine
Year Online:	2006
Heat Rate:	7,000 BTU/KWh
Capacity Factor:	90%
Variable O&M:	$2 Per MWh
Excess Sales:	75% of Market Price

Presently, there are at least two local generation options, which may be available to the City with respect to obtaining generation located within or near the City's boundaries:

(1) *Otay Mesa*: The Otay Mesa Generating Project (Otay Mesa) will be a 510 MW, natural gas-fired combined cycle power plant located in the Otay Mesa area in western San Diego County. Calpine Energy Services, LP (Calpine) is the project owner. The 15-acre site is about 15 miles southeast of San Diego, California, and about 1.5 miles north of the United States/Mexico border. SDG&E has recently announced plans to purchase most or all of the capacity from Calpine's Otay Mesa plant. If these plans are implemented, the option would not be available to the City. If SDG&E's proposal is not finally approved and implemented, the City should examine this option, as the MEU Study Team believes that there is still an opportunity to discuss potential teaming arrangements with Calpine.

Under current plans, a new 230-kV switchyard at the site is proposed. There are plans to build a 0.1-mile connection to SDG&E's existing 230-kV Miguel-Tijuana transmission line that passes near the eastern boundary of the Otay Mesa site. A new two-mile natural gas pipeline will be built by SDG&E to provide fuel for the project. Originally scheduled for completion in the summer of 2002, the construction schedule now calls for its completion by summer 2005. Currently the project is reported to be five percent complete.

(2) *South Bay Power Plant Repower (SBPP)*: The California State Lands Commission approved the San Diego Unified Port District's (Port District or Port) expenditure of $110 million in public trust funds to acquire the SBPP from SDG&E on January 29, 1999. The existing SBPP consists of four natural gas-fired conventional boiler units and one 14-megawatt combustion turbine.

Duke Energy North America's (Duke) 10-year lease with the Port District to operate the SBPP went into effect in April 1999. As part of its lease agreement with the Port District, Duke must, subject to certain conditions, dismantle and relocate the existing plant by 2009. According to the lease agreement, Duke must identify a specific relocation site no later than June 2006 and publicize its site selection as part of an application to the California Energy Commission (CEC) for permits to site the new plant.

Currently, the future of Calpine's Otay Mesa project and the siting of a new South Bay Power Plant remain unknown. The MEU Study Team's analysis indicates that the City is uniquely located to allow the City to potentially host either or both of these generation projects.

2. Distributed Generation

In addition to the evaluation of the Generation Supply Strategy, the MEU Study Team also evaluated the feasibility of acquiring or building small distributed generation units within the City to serve the customers of the City's MEU as a start-up strategy. With respect to this option, the MEU Study Team has concluded that there are no generation projects of sufficient size now operating within the City to support the development of an MEU. The MEU Study Team has also concluded that the development of small distributed generation projects is not economically feasible as a start-up measure in implementing an MEU.

Moreover, until the City successfully develops its Greenfield projects or forms an MDU and acquires the electric distribution system of SDG&E, it would have no means of delivering power from small City generation facilities to consumer electric loads (load). Without a distribution system, it would not be possible for the City to obtain delivery of power under the state's direct access laws and regulations and the Federal open access laws and regulations which apply to direct transmission access, except for the CCA-only option. Furthermore, the concept of developing distributed generation at selected sites around the City (e.g., main campus) would not provide a City-wide benefit and would offer very limited savings. As noted above (see Executive Summary Section I.(d)), the MEU Study Team was asked by the City to analyze feasible municipal energy businesses with the objective of "citywide distribution of MEU benefits."

At such time as the City develops a Generation Supply Strategy and has, through ownership or construction, a means of delivering power from local distributed generation projects to load, the MEU Study Team recommends that the City explore the development of local distributed generation projects to augment the City's power supply.

SECTION III

MEU STRUCTURAL OPTIONS

III. MEU STRUCTURAL OPTIONS

A. Summary

The MEU Study Team has examined all MEU structures which are presently authorized under the laws of the California, and has identified five structures which would accommodate Chula Vista's entry into the utility business. These include:

a) Community aggregation for both electricity and natural gas (CCA);
b) "Greenfield municipalization" development (Greenfield);
c) Municipalization under a city electric utility department format, eventually leading to a Municipal Distribution Utility (MDU) system;
d) Participation in a joint powers agency (JPA); and
e) Municipalization under a Municipal Utility District format (MUD).

Each of these options is discussed below.

B. Description of MEU Options

1. Community Choice Aggregation

Subject to the finalization and issuance of final rules by the CPUC, the City of Chula Vista can elect to serve as a community load aggregator for electric power pursuant to Assembly Bill 117.

A load aggregator is an entity that procures electric energy and/or natural gas for residents and businesses within a community. Under this option, the City would not own the electric or gas distribution system within the City. Rather, it would procure electric power and/or natural gas, either through its own generation, market purchases, or through a partner on behalf of the customers that choose to aggregate their load. SDG&E would then deliver the electric energy and/or natural gas to the end-use customer across its transmission and distribution facilities. As explained in Section IV.H at 152-54, the preliminary analysis of natural gas supply markets and costs shows that it is not economically feasible or desirable, at this time, for Chula Vista to undertake providing natural gas service, either by acquiring the gas distribution facilities of SDG&E or by implementing a Core Aggregation Transportation option for gas supply.

2. Greenfield Development

Greenfield development calls for the investment in distribution facilities to supply energy to certain previously undeveloped areas within the City of Chula Vista. Typically, this structure would include undeveloped acreage of land designated for an industrial park, for example, or for new residential subdivisions that are anticipated and planned for within the City's general plan build-out schedule. The distribution system should be planned and built in collaboration with the developers of the projects and much of the cost will be borne by the developers. The City may need to purchase a substation and would have to interconnect to SDG&E's system in some fashion in order to supply energy. The City would also need to develop the distribution system configuration (overhead/underground), lines, poles, and service extensions, as well as make arrangements for appropriate meters and related customer service functions. As discussed and demonstrated in Section IV.D of the Report at 80-98, the Greenfield development option can be implemented immediately in connection with current and future development of undeveloped areas within the City with positive financial results to the City and its electric consumers.

3. Combined Community Choice Aggregation/Greenfield Development

In this structural option, the City simple implements both the CCA option and Greenfield development option simultaneously and administers and operates the two programs using City Staff or outside contractors to oversee operations and the development of additional CCA and Greenfield development projects. As discussed and demonstrated in Section IV.B of this Report at 31-32, the City can obtain the greatest potential economic benefits in the near term by forming a CCA program and simultaneously pursuing and implementing Greenfield development opportunities.

4. Municipal Distribution Utility

A municipal corporation in California, unless restricted by the terms of its own Charter, has the legal authority to provide electric utility service to its residents and businesses. There are currently over thirty-seven municipal agencies that provide electric utility services to communities in California, representing approximately twenty-five percent of the total electric load within the state. With this optional utility structure, the City could acquire SDG&E's electric distribution system by negotiated price or condemnation and perform operation and maintenance activities. The City could also develop or acquire generation resources, and/or purchase power to meet the City's load requirements. The City Electric Utility Department could be used as a vehicle for providing utility services to certain customers within the City or to provide partial requirements service under agreements to be developed with SDG&E and other utility suppliers. However, for purposes of this section of the Report, the City Utility Department structure contemplates the formation of a Municipal Distribution Utility (MDU) which would acquire the electric distribution system of SDG&E and provide full utility service to retail electric customers within the City. As discussed in Section IV.F.7 of the Report at 132-34, the MEU Study Team recommends that the City first implement the CCA/Greenfield options and defer the consideration of implementation of an MDU until the 2008-10 time frame.

5. Joint Powers Agency/Municipal Utility District

Another optional utility structure is one in which the City forms, or becomes a member of an existing Joint Powers Agency (JPA) with one or more public agencies or utilities for the provision of electricity to their combined residents and businesses. In forming the JPA, the City would identify other potential participants and work on the development of a JPA agreement that would provide the legal basis of formation. The JPA agreement would also establish the roles, rights, and obligations of the participants.

A Municipal Utility District (MUD) is an agency of the state, formed to provide certain services of governmental or proprietary functions within limited boundaries. An MUD may acquire, construct, own, operate, control, or use public works located inside or outside of the district, as well as purchase power or other services, to supply the inhabitants of the district and public agencies therein with electric power. The MUD may construct works across or along any street or public highway, or over any lands that are property of the state, and it has the same rights and privileges granted to municipalities within the state, including the power of eminent domain. The MUD structure option provides for the aggregation of City electric loads and service territory with the electric loads those of other cities or unincorporated areas. While the City could use the MUD structure in lieu of forming its own MDU, the MEU Study Team does not recommend that the City pursue this option at this time. The complications of organizing an MUD and dealing with other local governments or entities would add complexities and complications and delay the implementation plan.

The JPA/MUD options would allow the Chula Vista MDU to accrue and realize further benefits by 1) the addition of partners to share the costs and risks of the MDU option; 2) possible aggregation of a larger load for resource procurement purposes, which, in turn, would lead to possible lower purchase power costs; and 3) possible reductions in cost for other activities associated with running an electric utility such as operation and maintenance functions.

As discussed in Section IV.G of the Report at 135, neither the JPA option nor the MUD option is feasible until and unless the City forms and implements the MDU option and becomes a full service electric distribution system. Once the MUD is formed, the JPA or MUD options are worthy of consideration as a means of obtaining the benefits of scale in generation projects and to allow the City to expand its portfolio of available energy options.

SECTION IV

EVALUATION OF CHULA VISTA'S MEU OPTIONS

IV. EVALUATION OF CHULA VISTA'S MEU OPTIONS

A. Introduction

As discussed and summarized in Section III above, the MEU Study Team initially identified all MEU options that were available to the City under applicable State and Federal laws and regulations. The initial screening of these MEU options included the possibility of developing both an electric and gas distribution system within the City. As discussed below in Section IV.H, at 152-54, the MEU Study Team has concluded that it will not be economically feasible for the City to acquire and operate a gas distribution system or otherwise engage in providing any gas utility services within the study period pending a significant change to the current cost structure and gas rates of SDG&E.

On the basis of the initial screening of the City's electric supply options, the MEU Study Team narrowed the number of MEU options based upon economic feasibility and then conducted a detailed economic feasibility analysis for the City of Chula Vista encompassing separate evaluation of three municipal electric utility options and corresponding electricity supply portfolios. These options are: 1) aggregation of electric loads within the city for purposes of procuring wholesale electricity through a Community Choice Aggregation program (CCA), as provided for in Assembly Bill 117 (2002); 2) ownership and operation of distribution assets in newly developed areas only (Greenfield development); and 3) acquisition of the existing SDG&E distribution assets within the city boundaries and assumption of ongoing distribution operations (MDU). A combined CCA/Greenfield option was also evaluated.

In addition to the three MEU options which were identified as feasible for immediate or near term development, the MEU Study Team also identified and evaluated two additional MEU options which would become available to the City in the long term in the event that the City develops a full service electric distribution system by acquiring the distribution system of SDG&E. The long range options which were evaluated and analyzed were (1) the development of a Municipal Utility District (MUD), and/or (2) participation in a Joint Powers Agency (JPA) to broaden the City's electric power supply alternatives.

As part of the detailed economic feasibility analyses, two primary supply strategies were evaluated for the City to serve the electric loads of its customers. The Generation Supply Strategy is built upon City ownership of or entitlement to 130 MW of new combined cycle gas turbine power plant capacity. This represents approximately 85% of the City electric loads under the CCA and MDU structure options (for further discussion see Appendix C, Section II.B.2 at 68-69). The Contracts Supply Strategy is based on the City entering into medium and short-term (1 to 5 years) fixed price power supply contracts to meet the majority of the MEU's load requirements.

IV. EVALUATION OF CHULA VISTA'S MEU OPTIONS
INTRODUCTION

The financial pro forma analysis compares the total costs of each option with the total costs of continued utility service from SDG&E, by year, through 2023. The model combines estimates of capital costs, power supply costs, operations and maintenance costs, and other applicable costs and then projects these costs over a 20-year period. Operations for each MEU option are not assumed to commence until 2006 in order to reduce the City's exposure to large CPUC exit fees. As detailed in the Appendix C, Section II.C.1 at 78-81, the CPUC exit fees that would be applicable to any of the MEU options are projected to start out high and steadily decline over time. Beginning operations in 2006 would reduce the risk that high exit fees would render the MEU options uneconomic. Therefore, the period analyzed to determine financial viability was the 18-year period beginning in 2006 and continuing through 2023.

B. Summary and Evaluation

Using the three basic municipal electric utility options identified above (*i.e.*, CCA, Greenfield Development and MDU), the MEU Study Team evaluated seven supply scenario options using different combinations of those feasible MEU options. Six of the seven combinations are expected to result in positive savings that are quantified in this section on a nominal and net present value basis[5]. Throughout this section, *savings* means the margin between projected MEU option costs and SDG&E's current and projected rates.

The pro forma results of all the supply scenario options or combinations are summarized in the table below. The table shows the total savings over the 18-year period from 2006 through 2023 and the net present value of these savings over the same time period.

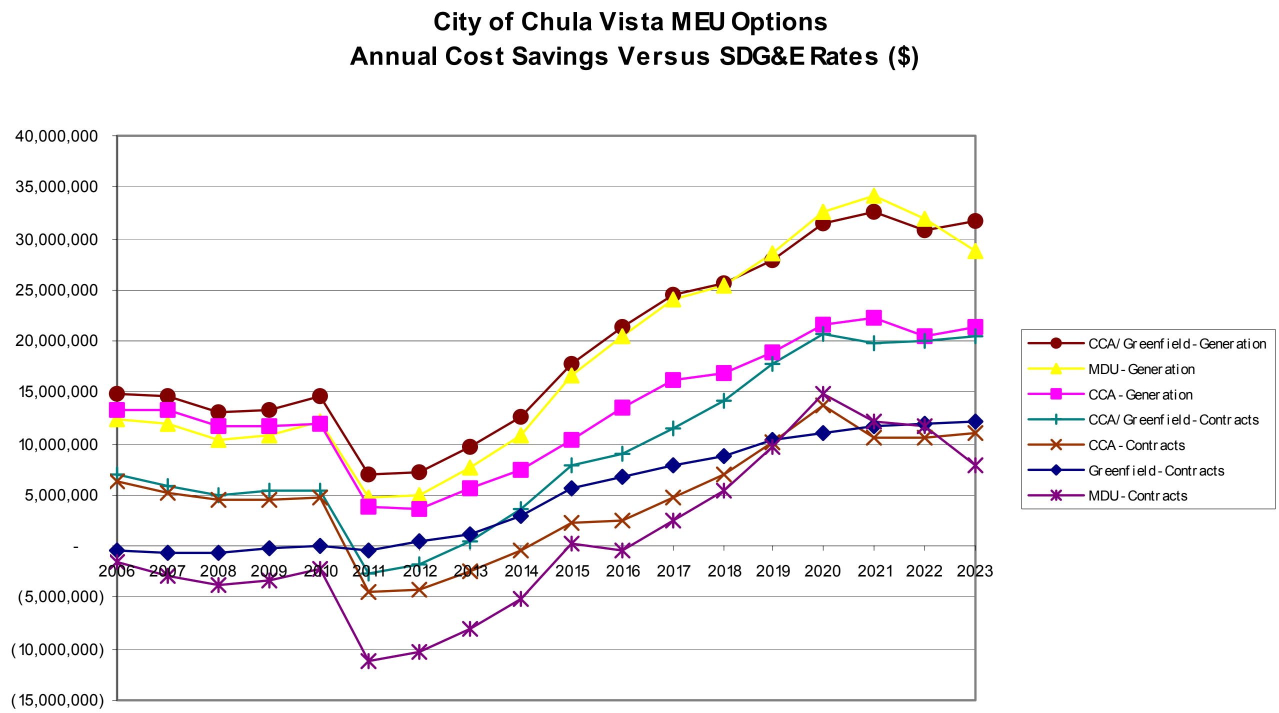
Summary of Savings Estimated For Each Option Ranked By NPV of Savings From 2006 Through 2023

Rank	Option	Supply Strategy	Nominal Savings ($ Millions)	NPV of Savings ($ Millions)	Average Annual Savings (%)
1	CCA/Greenfield	Generation	351	122	10%
2	MDU	Generation	329	109	9%
3	CCA	Generation	244	90	8%
4	CCA/Greenfield	Contracts	170	52	4%
5	CCA	Contracts	86	28	2%
6	Greenfield	Contracts	89	21	10%
7	MDU	Contracts	16	(12)	-1%

The year-by-year savings estimates for each option are shown in the following graph.

5 Net present value is a standard technique used in financial analysis of capital projects to account for the timing cash flows. Future cash flows are discounted to recognize the time value of money; i.e., dollars received in the future are worth less than dollars received today. A discount rate of 10% was used in the net present value calculations.

Annual Savings in Dollars For Each Option



The analysis demonstrates that the City can obtain the greatest potential benefit by forming a CCA and simultaneously pursuing Greenfield opportunities. Ideally, to maximize benefits, the City would acquire equity in a generation project within the City to supply the combined CCA/Greenfield loads. A CCA program gives the City the operational scale required to efficiently source electricity for the CCA and Greenfield customers and compete with the electric supply portfolio of SDG&E. The best approach for the City to obtain electricity at a lower cost than SDG&E is to secure an ownership interest in or entitlement to generation facilities located within the City. Such generation would give the City a competitive advantage relative to SDG&E, which should provide sustainable cost savings opportunities.

Another advantage to the CCA/Greenfield combination is that it positions the City for the possibility of forming an MDU if warranted by future circumstances. The City would obtain valuable experience in power supply and distribution system operations and would be in a more favorable position to form a City-wide MDU from a perspective developed by that experience.

SUMMARY AND EVALUATION

The analysis reveals the importance of generation ownership to the economics of any of the MEU options. The Generation Supply Strategy, with in-City generation, provides the maximum opportunity for electricity cost savings; savings are positive in every year for the hybrid CCA/Greenfield, CCA, and MDU options.

The Contracts Supply Strategy, under which the City purchases its electricity requirements from the market predominantly through long-term contracts, offers less benefit to the City than the Generation Supply Strategy. However, using the Contracts Supply Strategy the combined CCA/Greenfield option is projected to provide savings in all years and is a viable alternative. The CCA option is projected to provide savings in all years except for 2011 through 2014, when SDG&E rates are expected to decrease as a result of the expiration of DWR contracts embedded in the SDG&E generation portfolio cost. The Greenfield option is expected to lose money in the near term and commence realizing savings in 2012. The Contracts Supply Strategy does not support a viable MDU option at this time.

The Tables below highlight the projected Chula Vista rates for the following options: Community Choice Aggregation (Generation and Contract), Greenfield (Contract), CCA/Greenfield (Generation and Contract), and Municipal Distribution Utility (Contract and Generation). The projected average rates are for the period covering 2006 through 2023. The SDG&E comparable projected rates are included in the tables as a benchmark.

TABLE II-1
CCA
Comparison of Projected Average Rates ($/KWH)[6,7]

Term	Projected Load (KWH)	SDG&E	CCA Generation Option	CCA Contracts Option
2006	862,186,120	$0.086	$0.070	$0.078
2007	886,372,509	$0.083	$0.068	$0.077
2008	908,901,639	$0.080	$0.068	$0.075
2009	942,024,556	$0.081	$0.069	$0.076
2010	994,545,510	$0.081	$0.070	$0.077
2011	1,015,112,122	$0.075	$0.071	$0.079
2012	1,035,872,164	$0.076	$0.073	$0.080
2013	1,056,828,918	$0.078	$0.073	$0.080
2014	1,091,483,206	$0.080	$0.073	$0.080
2015	1,166,627,011	$0.082	$0.073	$0.080
2016	1,187,937,787	$0.084	$0.073	$0.082
2017	1,209,473,823	$0.086	$0.072	$0.082
2018	1,231,238,769	$0.088	$0.074	$0.082
2019	1,256,964,942	$0.090	$0.075	$0.082
2020	1,293,123,651	$0.092	$0.075	$0.082
2021	1,310,182,032	$0.094	$0.077	$0.086
2022	1,327,483,480	$0.094	$0.079	$0.086
2023	1,345,031,639	$0.090	$0.074	$0.082

Note: This table compares only the electric energy commodity. Under the CCA option SDG&E would continue to own and operate the distribution system.

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6 The Projected Average Rates are a composite of the actual rates for: Residential, Small Commercial (A), Medium Commercial (AL-TOU), Large Industrial (AL-TOU, +500KW), Street Lighting and Traffic Control.

7 These rates include CCA costs associated for generation. CCA customers would be separately responsible for transmission and distribution costs incurred by SDG&E.

TABLE II-2
Greenfield
Comparison of Projected Average Rates ($/KWH)[8]

Term	Projected Load (KWH)	SDG&E	Greenfield Contracts Option
2006	87,863,444	$0.147	$0.151
2007	93,848,667	$0.146	$0.152
2008	99,171,623	$0.142	$0.149
2009	114,758,650	$0.143	$0.145
2010	152,995,847	$0.144	$0.144
2011	163,334,325	$0.139	$0.141
2012	173,712,799	$0.141	$0.139
2013	184,132,061	$0.143	$0.138
2014	208,090,402	$0.146	$0.132
2015	271,146,613	$0.148	$0.128
2016	280,195,384	$0.151	$0.127
2017	289,286,261	$0.154	$0.126
2018	298,422,109	$0.157	$0.128
2019	311,332,418	$0.160	$0.127
2020	334,684,733	$0.163	$0.130
2021	340,374,374	$0.166	$0.131
2022	346,160,738	$0.166	$0.131
2023	352,045,471	$0.162	$0.127

Note: This table compares the total "bundled-service" cost for power supplied by SDG&E including costs associated with owning and operating the distribution system.

8 These rates include costs for generation, transmission and distribution.

TABLE II-3
Combined CCA/Greenfield
Comparison of Projected Average Rates ($/KWH)[9]

Term	Projected Load (KWH)	SDG&E	CCA/Greenfield Generation Option	CCA/Greenfield Contracts Option
2006	862,186,120	$0.092	$0.074	$0.083
2007	886,372,509	$0.089	$0.073	$0.083
2008	908,901,639	$0.087	$0.072	$0.081
2009	942,024,556	$0.088	$0.074	$0.082
2010	994,545,510	$0.091	$0.076	$0.085
2011	1,015,112,122	$0.084	$0.077	$0.087
2012	1,035,872,164	$0.086	$0.079	$0.088
2013	1,056,828,918	$0.089	$0.080	$0.088
2014	1,091,483,206	$0.092	$0.080	$0.088
2015	1,166,627,011	$0.096	$0.081	$0.090
2016	1,187,937,787	$0.099	$0.081	$0.091
2017	1,209,473,823	$0.101	$0.081	$0.091
2018	1,231,238,769	$0.103	$0.083	$0.092
2019	1,256,964,942	$0.106	$0.084	$0.092
2020	1,293,123,651	$0.109	$0.085	$0.093
2021	1,310,182,032	$0.112	$0.087	$0.096
2022	1,327,483,480	$0.112	$0.088	$0.097
2023	1,345,031,639	$0.107	$0.084	$0.092

9 These rates include CCA costs associated for generation and Greenfield costs associated with generation, transmission and distribution. Non-Greenfield customers would be separately responsible for transmission and distributions cost incurred by SDG&E.

TABLE II-4
MDU
Comparison of Projected Average Rates ($/KWH)[10]

Term	Projected Load (KWH)	SDG&E	MDU Generation Option	MDU Contracts Option
2006	862,186,120	$0.151	$0.137	$0.153
2007	886,372,509	$0.150	$0.136	$0.153
2008	908,901,639	$0.143	$0.132	$0.147
2009	942,024,556	$0.145	$0.133	$0.148
2010	994,545,510	$0.146	$0.134	$0.148
2011	1,015,112,122	$0.140	$0.135	$0.151
2012	1,035,872,164	$0.142	$0.137	$0.152
2013	1,056,828,918	$0.145	$0.138	$0.153
2014	1,091,483,206	$0.148	$0.138	$0.152
2015	1,166,627,011	$0.150	$0.136	$0.150
2016	1,187,937,787	$0.153	$0.136	$0.153
2017	1,209,473,823	$0.156	$0.136	$0.154
2018	1,231,238,769	$0.159	$0.138	$0.155
2019	1,256,964,942	$0.162	$0.139	$0.154
2020	1,293,123,651	$0.165	$0.140	$0.154
2021	1,310,182,032	$0.168	$0.144	$0.159
2022	1,327,483,480	$0.168	$0.144	$0.159
2023	1,345,031,639	$0.164	$0.143	$0.158

[10] These rates include costs for generation, transmission, and distribution.

The following sections of this Report describe each of the MEU options and the pro forma financial results of each option. Additional detail regarding the methodology and assumptions used to derive the financial pro forma are contained in Appendix C, Section II at 64-89.

C. Community Choice Aggregation

Under a CCA scenario, the City would procure electric supply for customers of the CCA, and SDG&E would continue to deliver the electricity to end use customers over distribution facilities owned and operated by SDG&E. Customers would pay SDG&E the retail rate for non-generation charges (e.g., transmission and distribution), as they do today. SDG&E would provide a credit on the bill to remove its costs related to generation and procurement of electricity that would be procured by the CCA. The bill credit that SDG&E will provide for generation-related charges is assumed to be the entire generation rate, net of the applicable exit fees. SDG&E would continue to perform metering and billing services for end use customers, the costs of which are largely bundled in existing retail distribution rates.

1. Customer Base

A CCA program would encompass all electric customers within the City boundaries, except for those who have notified the City of their desire to opt out of the CCA program and continue to receive electric commodity supply service from SDG&E. Section II. B at 9-16, describes, in detail, the customer and load projections used in the analysis, and these are summarized in the following table.

CCA Projected Customers, MWh, And Peak MW By Year

Year	Customers	MWh (usage)	Peak MW (demand)
2006	86,652	862,186	147
2007	89,412	886,373	151
2008	91,761	908,902	155
2009	94,149	942,025	160
2010	95,737	994,546	170
2011	96,567	1,015,112	174
2012	97,403	1,035,872	177
2013	98,244	1,056,829	181
2014	99,146	1,091,483	188
2015	100,028	1,166,627	201
2016	100,738	1,187,938	205
2017	101,449	1,209,474	209
2018	102,161	1,231,239	213
2019	102,875	1,256,965	217
2020	103,589	1,293,124	224
2021	103,881	1,310,182	227
2022	104,174	1,327,483	230
2023	104,469	1,345,032	233

The above chart assumes that the City, through its CCA program, will serve all customers within the City, including those in newly developed areas and that the City does not undertake a Greenfield Development project.

2. Functional Elements

a. Infrastructure Requirements

Assembly Bill 117 permits California cities, counties, or city and county JPAs, to implement a CCA to aggregate the electric loads of electric service customers within their jurisdictional boundaries to facilitate the purchase and sale of electricity. Within the context of CCA, "*electricity*" means the electric energy commodity only. CCA's enabling legislation requires the serving utility, in this case SDG&E, to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Accordingly, the infrastructure requirements of the CCA utility structure option do not include any electric transmission or distribution related facilities to serve CCA retail loads.

To support financial settlements and energy procurement, an accurate record of total, time-of-day specific, electricity demand and energy usage is essential. Lacking this, the CCA operator is required to rely on the distribution utility's recorded usage for each individual customer. All customer classes are not metered in the same way. In particular, residential and small commercial consumers (electric demand less the 20 kW) typically have simple electro mechanical meters capable of metering only cumulative energy consumption. Medium commercial customers (electric demand in the range of 20 to 500 kW) are typically metered with energy and demand meters, but still lack time-of-day recording. Large commercial and industrial customers (electric demand greater than 500 kW) are typically equipped with data recording meters recording electric demand on five, ten or fifteen minute intervals (interval data recording meters or IDR).

The CCA will be required to purchase energy on the wholesale market for each hour of the day. Without a time-of-use record of energy consumed, the operators will have to rely on prototypical rateclass load profiles. These *load profiles* are derived by distribution utility load research based on IDR metering of a stratified random sample from each rateclass (residential, small commercial, medium commercial). Hence, they represent the average or typical customer and not the CCA's actual customers. Further, since not all customers use energy at the same time, there will be diversity between each consumer's time-of-day usages. Simple aggregation, consisting of summing the metered values, will not reflect this diversity, and, since load diversity serves to reduce the total electric capacity required to serve the electric load, the operator will tend to over-procure capacity and increase operating costs.

CCAs have the option, under the law, to meter electricity supplied to the jurisdictional territories comprising the CCA to obtain an accurate record of aggregated loads. For the City's prospective CCA, SDG&E is required to "install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the CCA's political boundaries" at the request and at the expense of the CCA. SDG&E will also be required to "read the metering devices and provide the data collected to the CCA at the aggregator's expense."[11] Utilities are directed under CPUC Order Instituting Rulemaking R.03.09.007 (August 21, 2003) to develop specific tariff language to meet the requirements. Assessing the size, type, location, quantity and installation cost of such CCA wholesale metering will require an analysis of SDG&E's distribution system, in concert with SDG&E service planners, and, will require SDG&E to comply with the CPUC's Order to develop applicable tariff terms and conditions.

In addition to the upstream metering facilities described above, to facilitate electric portfolio operations required to procure wholesale energy for CCA supply, the systems identified below should be employed. The City may elect to procure or alternatively obtain system functionality by arrangement, which could be obtained through a full-requirements supply contract where the required systems and support services are bundled into a power contract and embedded in the commodity cost. However, such services are not free and systems and service costs must be known to quantify the embedded commodity premium to make informed procurement decisions.

System Requirements

System	Initial Cost	Maintenance	Annual Cost	Potential Outsourcing
Scheduling/Settlements Software	$650,000	40%	$476,667	Scheduling Coordinator
Risk Management Software	$150,000	40%	$110,000	Power Marketer
EDI/IOU Transactions	$100,000	40%	$73,333	Consultant
Scheduling Server	$50,000	10%	$21,667	Scheduling Coordinator
Total Systems Costs			$681,667	

Operations required for the systems are described under Section IV.C.2.c - Operations and Maintenance below at 44 and in Appendix C, Section II.B.3, Portfolio Operations at 77-78. Associated costs are included in financial analyses and pro forma results.

b. Resource Management

The MEU Study Team has modeled generation options for the City using operating and cost parameters of a new combined cycle gas turbine operating as a base load plant. These parameters include the unit's heat rate, capacity cost, variable O&M costs, availability factor, hours of planned operation, and the year the resource becomes operational.

[11] Cal. Pub. Until. Code §366.2(c)(18).

Sales of any excess production beyond what's needed to serve the city's load are sold into the market. The price for excess sales reflects a 25% discount relative to the prevailing peak or off-peak price to reflect the probability that excess sales will occur in the lowest priced hours of the on- or off-peak periods.

The following assumptions were used in the calculation of generation costs:

Capacity:	130 MW
Technology:	Combined Cycle Natural Gas Turbine
Year Online:	2006
Heat Rate:	7,000 BTU/KWh
Capacity Factor:	90%
Variable O&M:	$2 Per MWh
Excess Sales:	75% of Market Price

The CCA would benefit by ownership of generation within the City to supply the CCA relative to securing power through power purchase contracts. There are several reasons why a Generation Supply Strategy reduces total power supply costs. First, the production costs of a new combined cycle gas turbine are expected to be below market-clearing prices. In essence, the CCA would be able to capture generation profits within the CCA operation.

In addition, generation located within the City boundaries would enable the City to avoid paying grid management and transmission congestion charges which are assessed by the CAISO for use of the transmission grid when congestion is present. Electricity obtained via power purchase contracts may, or may not, be subject to charges for transmission congestion, depending on the point of delivery specified in the contract. Transmission charges for the fixed costs of the transmission network, as opposed to transmission congestion charges, are not impacted by the location of the generator due to the fact that, under CCA, the retail transmission rates of SDG&E will continue to apply.

The Contracts supply portfolio evaluated for CCA includes the following fixed priced contracts[12].

[12] Commercially traded power product descriptions in parentheses denote days per week and hours per day. "(6 X 16)" means six days per week, Monday through Saturday, and 16 hours per day, hours ending 07:00 through 22:00. Such definition is industry standard practice.

Power Purchase Contracts - CCA Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	50	49	5 Years
2006	Peak (6 x 16)	75	59	5 Years
2011	Base (7 x 24)	50	51	5 Years
2011	Peak (6 x 16)	75	61	5 Years
2016	Base (7 x 24)	75	51	5 Years
2016	Peak (6 x 16)	100	61	5 Years
2021	Base (7 x 24)	75	55	3 Years
2021	Peak (6 x 16)	125	66	3 Years

The following renewable energy contracts were assumed in the CCA portfolios for both the Generation and Contracts Supply Strategy:

Renewable Energy Contracts - CCA Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	7	52	1 Year
2007	Base (7 x 24)	8	51	1 Year
2008	Base (7 x 24)	10	52	1 Year
2009	Base (7 x 24)	11	52	1 Year
2010	Base (7 x 24)	13	52	1 Year
2011	Base (7 x 24)	15	53	1 Year
2012	Base (7 x 24)	17	54	1 Year
2013	Base (7 x 24)	18	54	1 Year
2014	Base (7 x 24)	20	54	1 Year
2015	Base (7 x 24)	23	54	1 Year
2016	Base (7 x 24)	25	53	1 Year
2017	Base (7 x 24)	28	53	1 Year
2018	Base (7 x 24)	29	55	3 Years
2021	Base (7 x 24)	30	58	3 Years

The CPUC has yet to determine how the Renewable Portfolio Standard (RPS) would apply to a CCA, and it is not clear whether an MDU would be required to meet the RPS. The MEU Study Team has assumed that the City's portfolio would match the minimum standards applicable to SDG&E in all of the MEU options. Accordingly, the portion of the portfolio comprised of renewable energy is established at 7% in 2006 and gradually increases to 20% in 2017, consistent with RPS requirements.

Additional details regarding the power supply portfolios modeled for the City, including treatment of spot market purchases and the RPS, are included in the Appendix C, Section II.B.2 at 68-77.

c. Operations and Maintenance

The primary operations and maintenance requirements for operation of a CCA program are activities related to electric portfolio operations. These activities include those necessary to procure electricity in the wholesale markets, schedule electricity transactions with the CAISO, conduct financial settlements for wholesale electricity purchases and sales, and interface with SDG&E which would be providing billing, metering, and customer services to CCA customers.

Portfolio operations costs are the costs associated with various activities related to procuring electricity for retail customers. Portfolio operations activities include load forecasting, procurement of electricity from wholesale electricity sellers, risk management and controls. Activities related to retail pricing (i.e., load research, cost of service, rate design) are also included in this cost category for purposes of the pro forma analysis.

Scheduling coordination costs are the costs associated with scheduling and settling electric supply transactions with the CAISO. The analysis assumes that the City would become a CAISO certified Scheduling Coordinator, which would require acquisition of scheduling and settlements software and operation of an around-the-clock scheduling desk.

Total costs of portfolio operations and scheduling coordination are modeled as a combination of fixed and variable costs. Fixed costs, largely associated with the minimum required personnel are approximately $2,000,000 per year. Variable costs are estimated at $2.50 per MWh to account for increases in the size and sophistication of the portfolio operations corresponding with increases in the overall size of the utility.

d. Human Resources

To facilitate electric portfolio operations described above, the City could develop the in-house capabilities or outsource the functions to a greater or lesser degree. As a base case to evaluate the efficacy of its potential outsourcing options, the following full-time employees (FTE) are required.

CCA Human Resource Requirements

Function	FTE	Potential Outsourcing
Rates/Forecasting	3	Consultant
Resource Planning	2	Consultant
Trading/Risk Management	4	Power Marketer
Wholesale Settlements	2	Scheduling Coordinator
Pre-Schedulers	2	Power Marketer
Real Time Desk	6	Scheduling Coordinator
Credit	1	Consultant
Management	3	
IOU Transactions/Audits	2	Consultant
IT Support	1	Scheduling Coordinator
Total	26	
FTE Average Annual Salary		$69,500
Fringe Benefits (15%)		$10,300
Annual Labor Estimates		$2,083,000

Associated costs are included in the financial analyses and pro forma results.

3. Cost-Benefit Analyses

a. Financial Analysis

A financial analysis was performed in order to develop financial pro forma, which was then structured as consolidated statement of income for each MEU structure option. The consolidated statements based on the financial pro forma for the CCA option are located in this Report in the Appendix C, Section II.I at 90-91. As noted above, savings or potential income is the margin between current retail power costs, as provided by SDG&E, and the given MEU structure option's projected cost to provide the power. The MEU Study Team began its evaluation of each utility structure option with a planning horizon beginning in 2004 and then projected costs 20-years forward to 2023. Evolving legislation, regulation, implementation lead times and cost considerations caused the MEU Study Team to project MEU implementation beginning in 2006. The resulting study period was subsequently revised from 2006 to 2023 as reflected in the financial pro forma for each MEU structure option.

As a regulated public utility, SDG&E provides utility services at regulated cost-based rates. Hence, SDG&E's rates are directly tied to a demonstrated revenue requirement and its rate structures are required to reflect an equitable cost allocation among customer classes. The financial analysis provided herein compares SDG&E's revenue requirement with the revenue requirement of each MEU structure option to determine potential savings or income. Pro forma summary tables compare each MEU structure option based on their relative ability to produce operational cost savings or benefits.

In the CCA option, customer service is limited to the electric energy commodity only. SDG&E would continue to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Accordingly, to evaluate the potential benefits for CCA, only costs associated with wholesale electric commodity procurement and related business expenses were evaluated to assess potential savings or benefits.

b. Financial Analysis Structure

CCA customer population electric loads, evaluated under Section II.B at 9-16 and summarized above at 39 , were applied to SDG&E current and projected generation rates to yield its revenue requirement or retail customer energy costs. MEU operating expenses were projected and subtracted from SDG&E's revenue requirement to yield the projected financial benefit. Elements contained in the analysis are summarized below:

SDG&E Forecast Generation Rates [13]
- Utility Retained Generation
- Qualifying Facility Generation
- Bilateral Power Purchase Contracts
- CAISO charges
- Residual Spot Market Purchases or Sales

CCA Energy Cost (Commodity Costs)[14]
- Spot Market Purchases
- Power Purchase Contracts
- Renewable Energy Contracts
- Generation Ownership

California Independent System Operator Charges (CAISO)[15]

Transmission
Ancillary Service
Grid Management
Reliability Services
Congestion Costs
Grid Operations
Unaccounted for Energy

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13 Detailed explanation of inputs, assumptions and sources are provided in Appendix C, Section II.A at 64-67.

14 Detailed explanation of inputs, assumptions and sources are provided in the Appendix C, Section II.B.2 at 68-77.

15 Detailed explanation of inputs, assumptions and sources are provided in the Appendix C , Section II.D at 83-84.

Neutrality Adjustments
Deviation Charges

Operation and Scheduling Costs[16]
Scheduling and Settlements System - Procurement and Maintenance Costs
Labor

Non-Bypassable Charges[17]
CPUC Exit Fees
Uneconomic Utility Retained Generation and Power Contracts
DWR Power Purchase Contracts
DWR Bond Charges - Financing Past Purchases

As related in Section II.C, MEU structure option cost benefits are assessed based upon two energy supply strategies. In the first supply strategy, it is assumed the City's MEU will take an ownership position in a power generation facility (Generation Supply Strategy). In the second, it is assumed the City's MEU will purchase all of its energy requirements in the wholesale energy market by executing power contracts with suppliers (Contracts Supply Strategy). Power costs are allocated to portfolio supply options for each supply strategy as follows:

Power Supply Portfolio Energy Cost ($)

Illustrative - 2006 Only

	Generation	Contracts
Market Purchases	8.6%	5.6%
Contracts	6.4%	94.4%
Power Production	85.0%	

c. Pro Forma Results

Financial pro forma results were prepared for the CCA option for both of the *Generation* and *Contracts* Supply Strategies. *See* Appendix C, Section II.I at 90-91.

16 Detailed explanation of inputs, assumptions and sources are provided in Appendix C, Section II.B.3 at 77-79, as well as in Sections IV.C.2.a, b and c at 40-44, above, addressing Infrastructure Requirements, Operations and Maintenance, and Human Resource Requirements, respectively.

17 *See* Appendix C, Section II.C at 78-81.

(1) CCA - Generation Supply Strategy

Total estimated costs of CCA operations are summarized in the table below for the Generation Supply Strategy and these costs are compared to projected SDG&E electric commodity related charges. The costs of CCA operations are broken out among the major cost-of-service elements. The most significant of these costs is the electric commodity costs, which are primarily the capital and operating costs of the CCA's generator, plus renewable energy contracts and residual spot market purchases. The next largest cost category relates to the non-bypassable charges or exit fees that SDG&E will impose on the CCA pursuant to CPUC authority. Other costs include ancillary services, CAISO charges and portfolio operations and scheduling coordination charges.

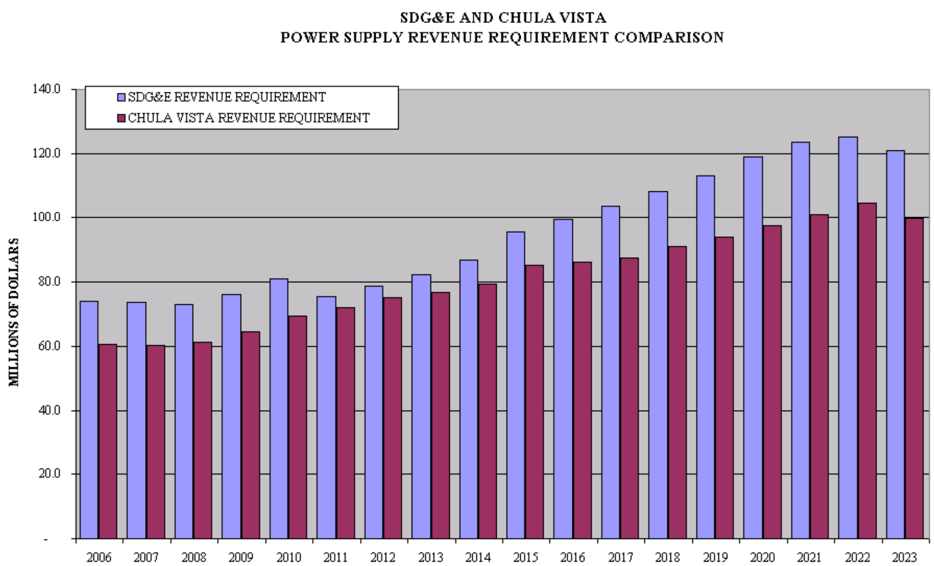
Savings are the difference between the CCA costs and the charges that SDG&E would collect through rates under the status quo retail electric service arrangement. As shown below, significant savings are projected to occur in every year of the study period.

Pro Forma Summary and Projected Savings - CCA Generation Supply Strategy (Millions of Dollars Per Year)

Year	Commodity Costs	Ancillary Services/ISO Costs	Operations & Scheduling	Non-bypassable Charges	Total Costs	SDG&E Charges	Savings
2006	44.2	2.4	4.2	9.8	60.5	73.9	13.3
2007	44.3	2.5	4.2	9.1	60.2	73.4	13.2
2008	46.6	2.7	4.3	7.8	61.4	73.0	11.6
2009	48.7	2.9	4.4	8.7	64.6	76.2	11.6
2010	51.6	3.2	4.5	9.9	69.2	81.1	11.9
2011	53.5	3.4	4.5	10.5	71.9	75.7	3.8
2012	55.5	3.6	4.6	11.5	75.2	78.8	3.6
2013	56.5	3.7	4.6	11.8	76.7	82.4	5.7
2014	58.7	4.0	4.7	12.0	79.4	87.0	7.5
2015	63.0	4.4	4.9	12.9	85.3	95.5	10.3
2016	63.4	4.6	5.0	13.1	86.1	99.6	13.5
2017	64.4	4.7	5.0	13.3	87.5	103.7	16.3
2018	67.4	5.0	5.1	13.6	91.1	108.1	17.0
2019	69.8	5.3	5.1	13.9	94.1	113.0	18.9
2020	72.4	5.6	5.2	14.3	97.6	119.1	21.5
2021	75.6	5.9	5.3	14.5	101.2	123.5	22.3
2022	78.5	6.1	5.3	14.6	104.6	125.1	20.5
2023	78.9	6.3	5.4	9.1	99.7	121.0	21.3

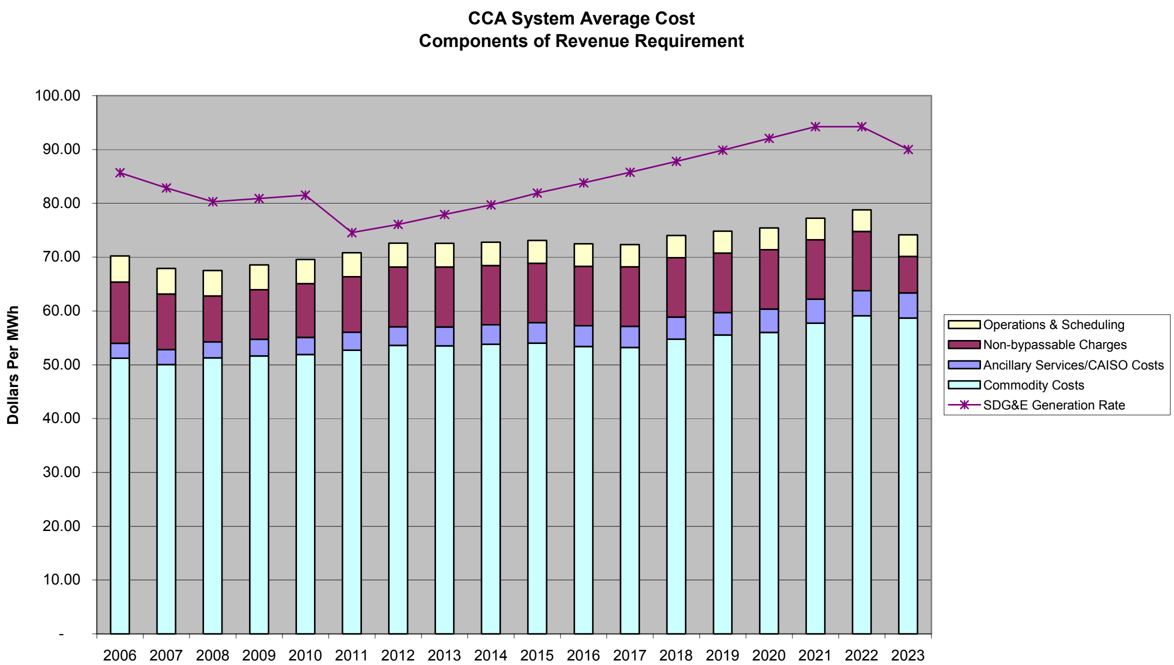
The following Chart 1 graphically compares the total CCA cost of service, to the generation-related charges projected for SDG&E.

Chart 1: Comparison Of CCA Costs Based On Generation Supply Strategy



The components of the CCA costs on a dollar per MWh basis are shown in Chart 2 for the Generation Supply Strategy and are compared to SDG&E electric commodity related rates.

Chart 2: CCA Cost Components On A Per MWh Basis



(2) CCA - Contracts Supply Strategy

Total estimated costs of CCA operations are summarized in the table below for the Contracts Supply Strategy and are compared to projected SDG&E electric commodity related charges. The most significant of these costs is the electric commodity costs. The commodity costs primarily reflect the long-term power purchase contracts that form the core of the supply portfolio, as well as the renewable energy contracts and spot market purchases.

Cost savings are projected to occur in years 2006 through 2010. Projected SDG&E rate reductions in 2011[18], resulting from the expiration of DWR power purchase contracts in SDG&E's supply portfolio, eliminate the savings from 2011 through 2014. At that time, modest annual increases in SDG&E rates are projected to provide persistent savings opportunities for the CCA throughout the remainder of the study period.

18 See Appendix C, Section II.A at 64-65 for SDG&E Forecast Rates.

Pro Forma Summary and Projected Savings - CCA Contracts Supply Strategy
(Millions of Dollars Per Year)

Year	Commodity Costs	Ancillary Services/ISO Costs	Operations & Scheduling	Non-bypassable Charges	Total Costs	SDG&E Charges	Savings
2006	49.6	3.9	4.2	9.8	67.5	73.9	6.3
2007	50.8	4.0	4.2	9.1	68.2	73.4	5.3
2008	52.2	4.3	4.3	7.8	68.5	73.0	4.5
2009	54.1	4.5	4.4	8.7	71.6	76.2	4.6
2010	57.1	4.8	4.5	9.9	76.3	81.1	4.8
2011	60.2	5.0	4.5	10.5	80.2	75.7	(4.5)
2012	61.7	5.2	4.6	11.5	83.0	78.8	(4.2)
2013	62.9	5.4	4.6	11.8	84.7	82.4	(2.4)
2014	65.0	5.7	4.7	12.0	87.4	87.0	(0.4)
2015	69.4	6.1	4.9	12.9	93.3	95.5	2.2
2016	72.5	6.5	5.0	13.1	97.1	99.6	2.4
2017	73.9	6.7	5.0	13.3	99.0	103.7	4.7
2018	75.4	7.0	5.1	13.6	101.1	108.1	7.0
2019	76.6	7.3	5.1	13.9	102.9	113.0	10.1
2020	78.3	7.6	5.2	14.3	105.5	119.1	13.6
2021	85.3	7.9	5.3	14.5	112.9	123.5	10.6
2022	86.2	8.2	5.3	14.6	114.4	125.1	10.7
2023	87.1	8.4	5.4	9.1	110.1	121.0	11.0

The following Chart demonstrates that the implementation of the Generation Supply Strategy would result in substantially greater benefits than the Contracts Supply Strategy if the City implements the CCA option:

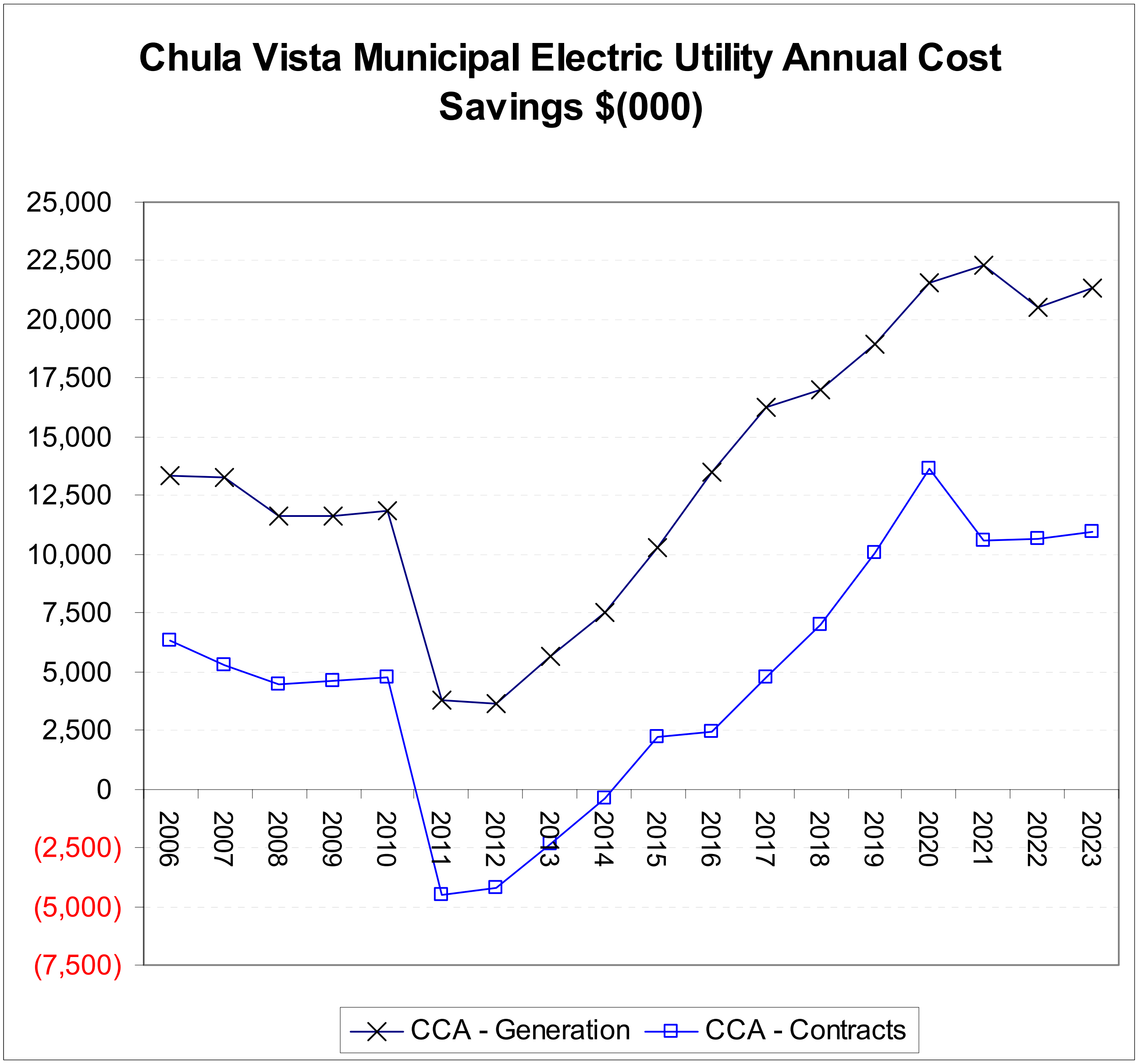
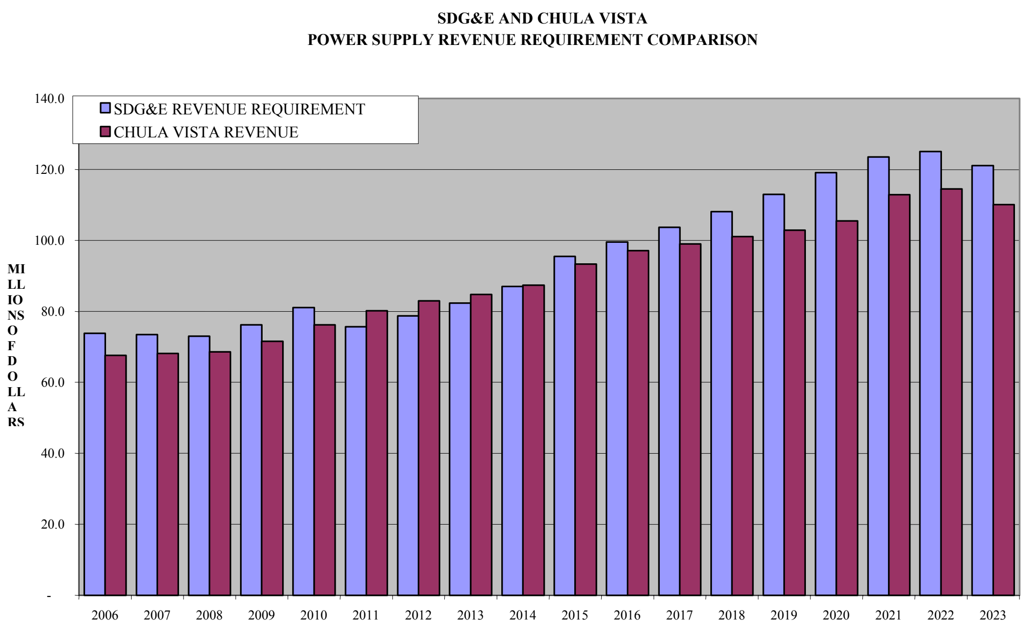


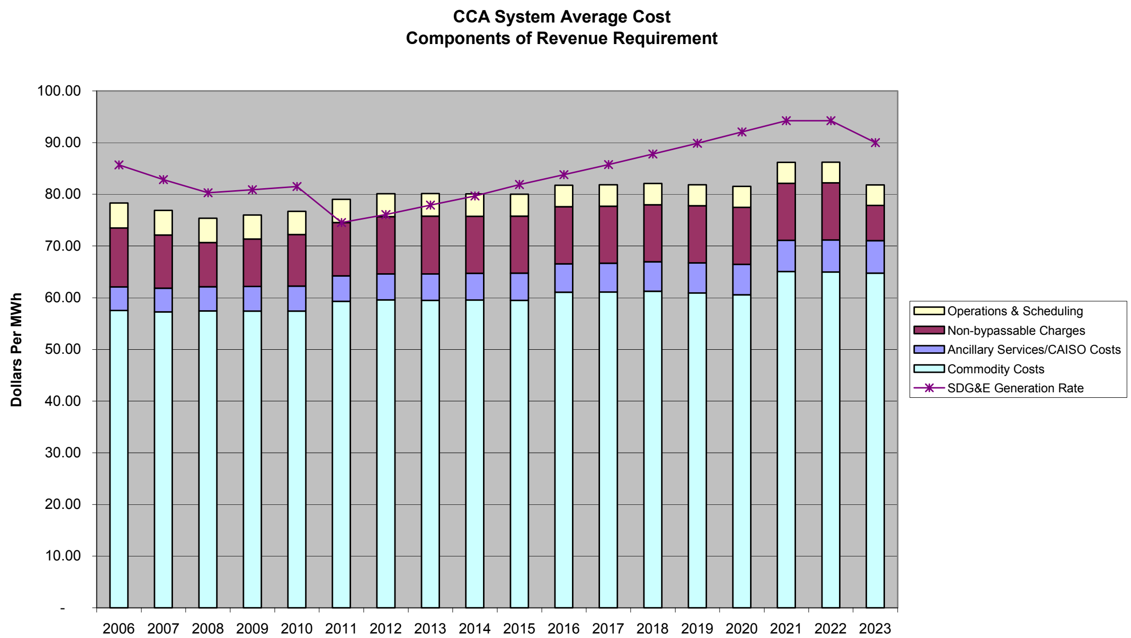
Chart 3 graphically compares the total CCA cost-of-service to the generation-related charges projected for SDG&E.

Chart 3: Comparison of CCA Costs Based on Contracts Supply Strategy



The components of the CCA costs on a dollar per MWh basis are shown below in Chart 4 for the Contracts Supply Strategy and compared to SDG&E electric commodity related rates.

Chart 4: CCA Cost Components On A Per MWh Basis



d. Intangibles

(1) Benefits

The major benefit available through the electric utility aggregation option is that the City could begin procuring electric energy and supplying it to retail customers without the need to purchase the SDG&E electric distribution system.

(2) Risks

On the electric utility side, if the City elects to pursue this option, the CPUC must confirm or approve the City's implementation plan before final steps to implementation can occur. At this juncture, it is uncertain how the CPUC will analyze any implementation plan submitted by the City in light of the current controversy over direct access, exit fees and scheduling coordination services. As stated above, while AB 117 does provide a statutory basis for CCA programs, the CPUC has not yet established and implemented the rules for the approval of a CCA implementation plan.

4. Legal/Regulatory

CCA is governed by the Community Choice Aggregation legislation (AB 117, Chapter 838, September 24, 2002[19]), and the CPUC's corresponding proceeding, Rulemaking 03-10-003 (R.03-10-003). If the City elects to pursue the CCA option, the CPUC must confirm or approve the implementation plan before final steps to implementation can occur. Pursuant to R.03-10-003, the CPUC is to determine the implementation requirements for CCA, including the level of any applicable cost responsibility surcharges, IOU administrative charges, and other costs and restrictions that may be developed. The parameters of the CPUC's proceeding will dictate the rules governing CCA programs. On November 26, 2003, the assigned Administrative Law Judge in R.03-10-003 issued a ruling bifurcating the proceeding into two phases. The first phase, which is scheduled for hearings for February 2004, will address many of these cost related issues. Administrative and ministerial matters will be the subject of the second phase of the proceeding. Because AB 117 authorized an "opt out" program rather than an "opt in" program, the City can sign up customers willing to switch from SDG&E generation service to City service without the necessity of developing an active marketing effort to lure customers. Instead, the City would merely need to notify customers of the impending community choice aggregation program. Any customers that do not want to participate in the program would be required to notify the City of their election to "opt out" within a specified amount of time. The specific rules governing customer notices will be developed during the course of R.03-10-003.

AB 117 also requires full cooperation by the host investor owned utility (SDG&E) in any CCA program implemented by the City. In this regard, SDG&E is required to provide necessary load information and other important data to the City, and continue to provide transmission, distribution, metering, meter reading, billing and other essential customer services. Under AB117 and the initial rules outlined by the CPUC in R.03-10-003, SDG&E would remain the backup service provider for the City's CCA customers.

5. Financing Options

Implementing a CCA program would not require *major* capital outlays, with the possible exception of capital required for generation acquisition. Acquiring interest in a generation project to support the Generation Strategy would require initial capital expenditures estimated at $78 Million. This figure is derived on the basis of an assumed ownership of 130 MW of generation at an installed capital cost of $600,000 per MW. Annual debt service to support this investment would be approximately $5.4 million at an assumed tax-exempt debt interest rate of 5.5% for an amortization period of 30 years.

[19] AB 117 became effective January 1, 2003 amends Sections 218.3, 366, 394, and 394.25 of the Public Utilities Code and adds Sections 331.1, 366.2, and 381.1 to the same Code.

The City would have a variety of financing mechanisms available to finance its MEU projects depending upon the specific asset and/or activity. Financing techniques might include the following:

- General Obligation Bonds
- Limited Obligation Bonds
- Special Assessment
- Certificates of Participation
- Revenue Bonds
- Commercial Paper

In Appendix C, Section IV.A, at 126-27, the MEU Study Team has provided an overview and comparative analysis of each type of financing vehicle that is available to the City.

6. Implementation Schedule

a. Major and Critical Steps

The MEU Study Team recommends a two-track approach to evaluate and implement a CCA project. The following outlines the associated critical path elements for each track of work:

(1) <u>Track 1 Tasks</u>

1.1 - Project Initiation - Orientation Sessions for Elected Officials and Staff

1.2 - Base Case Feasibility Studies

- Load Forecasts
- Cost-of-Service Analyses

1.3 - Regulatory Engagement-A

Participation in CPUC CCA proceedings and workshops for the development of costs and credits, rules and protocols; use base case feasibility studies performed under (1.2) as the basis to demonstrate the impacts of proposed decisions.

1.4 - Track-1 Report:

Update base case feasibility study with final CPUC adopted costs, credit rules and protocols; evaluate results and make threshold decision whether or not to proceed with implementation.

1.5 - CPUC Implementation Plan

- Develop program structure, organization, operations plans and funding
- Perform Rate Design (cost allocation methodology and disclosure)
- Document participant rights and responsibilities
- Finalize energy supply resource portfolio
- Adopt Implementation Plan in a public hearing[20]
- Pass City Ordinance to implement CCA as defined in the Implementation Plan[21]
- File the Implementation Plan with the CPUC

Where third-party suppliers are indicated, evaluate and document their financial, technical and operational capabilities. If the City intends to pursue an equity position in generation resources document the same capabilities of the City and/or its equity partners.

1.6 - Regulatory Engagement-B

Monitor, participate and respond as required to CPUC proceedings and processes to approve or reject the City's filed Implementation Plan. Pending CPUC approvals, begin Track 2 tasks.

(2) <u>Track 2 Tasks</u>

2.1 - CCA Implementation

2.1.1. - Register the CCA with the CPUC (may become part of 1.5 above)

2.1.2. - Execute Investor-Owned Utility (IOU) Service Agreement [22]

2.1.3. – Determine Required Aggregated Load Metering Facilities [23]

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20 Cal. Pub. Util. Code §366.2 (c)(3). ("The implementation plan, and any subsequent changes to it, shall be considered and adopted at a duly noticed public hearing".)

21 Cal. Pub. Util. Code §366.2 (c)(10)(A).

22 The City, as a CCA operator, will need to establish a legal relationship with SDG&E. It is anticipated that a service agreements will include processes for information exchange, including electronic data interchange, procedures for settling financial transactions, treatment of customer bill payment funds transfer, credit terms, access to confidential customer information, audit provisions, and regulatory oversight and complaint processes.

2.1.4. - Complete Arrangements for 60-Day Customer Notification
And Opt-Out Provisions

2.1.5. - Notify SDG&E When CCA Service Will Begin

2.2 - CCA Operation (iterative and on-going activities)

2.2.1. - Activate Energy Supply Resource Plan
- Execute Supply Contracts
- Schedule Generation Resources

2.2.2. - Update Load Forecast and Optimize Scheduling

2.2.3. - Manage Supply Portfolio and Risk Management

2.2.4. - Process Financial Settlements

2.2.5. - Produce Operating Statements and Reports

b. Timelines

At the termination of this study period, the City will have completed Tasks 1.1 and 1.2. The CPUC proceedings began on August 21, 2003 and appear to be moving ahead in a manner to meet the CPUC's expectation of lasting between six and nine months or until approximately mid-2004. The MEU Study Team strongly recommends that the City remain actively involved in the ongoing CPUC proceedings in order to help shape the CCA implementation costs, credit rules and protocols. The MEU Study Team estimates that a CCA could be operational by 2006. Please refer to Section V.C at 165 and Appendix C, Section V at 130, for Gantt Chart time requirement projections for each Task described above.

7. Recommendation

The MEU Study Team recommends that, subject to the establishment of satisfactory rules and protocols by the CPUC, the City perform Track 1 and 2 Tasks leading to the formation and implementation of Community Choice Aggregation program within the City to enable the City to commence providing electric utility services to electric consumers within the City as early as 2006.

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[23] Identify whether additional metering devices described in Section IV.C.2.a at 40 can be employed. If feasible and warranted, place a service orders with the IOU to have them installed.

D. Greenfield Development

The Greenfield municipal utility structure entails the City owning the new electric distribution facilities in selected developing areas. In newly developing areas in which SDG&E has yet to install distribution infrastructure, the City can exercise its constitutional authority to begin to provide electric utility service, and avoid the challenges and expense of acquiring the existing electric distribution system of SDG&E. The process of implementing a Greenfield MEU structure is detailed below in Section IV.D. 6 at 77-79 (Implementation Schedule, (a) Major and Critical Steps).

Typically, these steps involve land developers performing the identical distribution system construction elements required of them as if the area were to be served by SDG&E. The difference occurs when the City, as a serving public utility, takes delivery of wholesale power at the development site's interconnection point (substation) and then resells the power to end-use consumers located within the newly developed areas. The City utility will operate and maintain the facilities, establish retail electric rates, and perform all of the functions of a traditional municipal utility (customer service, account services, metering and billing). The creation of a Greenfield utility is possible for the City's consideration at any or in all of the currently undeveloped portions of the City. The MEU Study Team has worked with City Planning Division Staff to identify such prospective new development areas. Based upon planned land use in these areas, the MEU Study Team modeled the site-specific energy requirements in each of the undeveloped areas identified by the Planning Division Staff.

1. Customer Base

A Greenfield operation would encompass all future electric customers within selected newly developing areas of the City. Section II.B at 9-16 describes, in detail, the customer and load projections used in the analysis, and these are summarized in the following table.

Greenfield Projected Customers, MWh, And Peak MW By Year

Year	Customers	MWh	Peak MW
2006	4,017	87,863	16
2007	4,950	93,849	17
2008	5,728	99,172	18
2009	6,540	114,759	20
2010	7,424	152,996	27
2011	7,656	163,334	29
2012	7,888	173,713	31
2013	8,120	184,132	33
2014	8,408	208,090	37
2015	8,811	271,149	48
2016	9,040	280,195	50
2017	9,270	289,286	52
2018	9,499	298,422	53
2019	9,729	311,332	55
2020	9,965	334,685	60
2021	10,041	340,374	61
2022	10,117	346,161	62
2023	10,193	352,046	63

2. Functional Elements

a. Infrastructure Requirements

(1) Distribution System Infrastructure

Prior to addressing the distribution system requirements for the Greenfield option, an overview of the Greenfield opportunity and load forecast bases is instructive. The MEU Study Team worked with City Planning Staff to identify the potential development areas that are not currently served by existing SDG&E distribution infrastructure. Development areas and planned land-uses were identified, as well as estimated development schedules. Development areas were defined according to SANDAG Traffic Analysis Zones (TAZ) and Land-Use Definitions. The approach supports a City-wide Greenfield utility market potential based on the analysis and the load forecast discussed in detail in Section II.B at 9-16 and summarized above.

The development areas identified are located within eighteen traffic analysis zones that are grouped roughly into six potential Greenfield development areas. These areas are geographically dispersed from one another and with varied development schedules. These are described below:

Potential Greenfield Development Areas

Area	***Description***	***Commercial***	***Residential***	***Most Active Development Periods***
1	*Bayfront*	*7.3%*	*10.8%*	*continuous*
2	*Sunbow/Village 2 Village 2-West, Village 3, Area 18b*	*5.1%*	*25.1%*	*2005-2010*
3	*Eastlake/Otay Ranch/ McMillin Freeway Commercial*	*7.2%*	*41.3%*	*2010-2015*
4	*University Areas*	*7.8%*	*0.0%*	*2015*
5	*Village 4, 8 and open space*	*43.4%*	*21.4%*	*2015*
6	*Remote University Land*	*29.1%*	*0.0%*	*not active*
		100.0%	*100%*	

The "major and critical steps" to implementation provided in Section IV.D.6 below at 77-79 identify the need for electric distribution design firms to work with developers to design and specify system requirements in compliance with applicable design standards to serve the planned developments. Given the varied and yet-to-be defined infrastructure requirements of potentially six different development areas, it would be inappropriate and practically impossible for the MEU Study Team to attempt an estimate of the number, size and location of trenching, conduit, vaults and other substructures or required electrical equipment such as conductors, connectors, switches, transformers or substations.

Suffice it to say, that the Greenfield option requires the investment in the distribution infrastructure described above. The Greenfield utility activity would also require infrastructure to support the operations and maintenance of the distribution system. These include service vehicles, maintenance crews and equipment inventories as well as infrastructure to support customer service functions and investment in customer call centers and billing operations.

Additional infrastructure requirements include those necessary for the activities related to electric portfolio operations. These activities include those necessary to procure electricity in the wholesale markets, schedule electricity transactions with the CAISO, and conduct financial settlements for wholesale electricity purchases and sales.

To estimate distribution facilities cost, the MEU Study Team relied on the benchmarked replacement-cost-new amount of $3,000 per customer described and supported in Appendix C, Section II.E at 84-87.

Section IV.D.6.a below at 77-79 identifies major and critical steps required to implement a Greenfield utility option. Step 6.a (8) describes high-voltage subcontractors installing the electrical components. Currently, developers are reimbursed for certain costs associated with this step by SDG&E and most of the state's electric utilities. The financial analyses of potential Greenfield benefits must show that the City can capture these costs. If Greenfield promoters fail to account for costs, the affect is a cost shift from utility operations to developers and ultimately to project occupants. Developers and the California Building Industry Association oppose such practices.

(2) Interconnection/WDAT Costs

The development of a Greenfield utility option would require that the City take wholesale transmission service from SDG&E and/or the CAISO. The City will need to develop the necessary infrastructure to interconnect with SDG&E. The City may not be interconnected with SDG&E at a transmission voltage, but rather at a distribution voltage, and therefore, the City would not only take wholesale transmission services from SDG&E, but also take service under SDG&E's WDAT, a copy of which is included as Appendix D.

The cost for taking wholesale distribution service under the WDAT would be determined by SDG&E based on an assessment of the actual distribution facilities utilized by the City. SDG&E would perform a study to determine the allocated portion of pre-existing facilities that should be assigned to the Greenfield utility as well as any new facilities, which are required to interconnect the Greenfield utility to SDG&E's system. SDG&E would then apply a fixed carrying charge percentage to determine an annual revenue requirement and monthly demand charge for the distribution facilities. The fixed carrying charge is derived to recover SDG&E's cost of capital, depreciation, operations and maintenance expenses, and tax expenses related to the facilities. The monthly demand charge would be applied to the monthly kW demand recorded at the meter at the interconnection point between the Greenfield distribution system and SDG&E's system.

The first year costs for constructing the distribution infrastructure needed to serve the Greenfield areas are estimated at $13.8 million. These costs include the following:

Investment	Cost
Distribution Facilities	$12.1 Million
Interconnection/WDAT	$0.7 Million
Regulatory/Litigation	$0.5 Million
Inventory	$0.5 Million
Total	$13.8 Million

The infrastructure requirements identified herein will result in implementation costs of $13.8 million. These costs will be amortized over 30 years with an annual debt service to support the investment of approximately $1.3 million, at an assumed tax-exempt debt interest rate of 5.5% (see Pro Forma table below at 74 under Distribution Capital. Operational costs are reflected as annual costs in financial pro forma under "Distribution O&M").[24]

b. Resource Management

In developing the resources for the Greenfield utility business model, the MEU Study Team determined the stand-alone Greenfield utility was not of a sufficient size to support the development of a generation project. Therefore, the projected power supply for the Greenfield utility is 100 percent contract based. The electric supply portfolio evaluated for Greenfield includes the following fixed priced contracts.

Power Purchase Contracts - Greenfield Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	5	49	4 Years
2006	Peak (6 x 16)	10	59	4 Years
2010	Base (7 x 24)	12	50	5 Years
2010	Peak (6 x 16)	15	60	5 Years
2015	Base (7 x 24)	15	51	5 Years
2015	Peak (6 x 16)	25	61	5 Years
2020	Base (7 x 24)	20	54	4 Years
2020	Peak (6 x 16)	25	65	4 Years

24 *See* Appendix C, Section II.I at 92, line V.(B)(i).

Renewable Energy Contracts – Greenfield Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	1	52	1 Year
2007	Base (7 x 24)	1	51	1 Year
2008	Base (7 x 24)	1	52	1 Year
2009	Base (7 x 24)	1	52	1 Year
2010	Base (7 x 24)	2	52	1 Year
2011	Base (7 x 24)	2	53	1 Year
2012	Base (7 x 24)	2	54	1 Year
2013	Base (7 x 24)	3	54	1 Year
2014	Base (7 x 24)	3	54	1 Year
2015	Base (7 x 24)	5	54	1 Year
2016	Base (7 x 24)	5	53	1 Year
2017	Base (7 x 24)	5	53	1 Year
2018	Base (7 x 24)	7	55	3 Years
2021	Base (7 x 24)	8	58	3 Years

A generation portfolio was not evaluated for the Greenfield option due to the infeasibility of sizing and locating a base load facility within the small geographic areas served by the Greenfield utility. Small, distributed generation (DG) could be used to supply the Greenfield areas. However, stand-alone DG units operate at a lower efficiency than central station power, and the use of DG would not represent a cost-effective substitute for wholesale market purchases, absent some cost-mitigating factor. The benefits of DG are typically attainable where there is a cogeneration opportunity that utilizes thermal energy for a different production process or when "behind the meter" DG can be used to reduce the retail rates paid to the local utility. Under the Greenfield option, the City becomes the incumbent utility. Under this scenario, a significant portion of the DG benefits (avoidance of certain incumbent utility charges) would no longer be applicable to the City in consideration of DG in the Greenfield utility model.

In the case of cogeneration, the efficiency gain from converting waste heat to usable energy can make DG cost-effective. In the case of behind the meter DG, the DG unit can cost-effectively compete with the higher retail rate of the utility. In contrast, a standalone DG used to supply the Greenfield utility would be forced to compete directly with the wholesale market price, which typically reflects the superior operating efficiency of central station power.

Additional details regarding the power supply portfolios modeled for the City is included in Appendix C. [25]

[25] *See* Appendix C, Section II.B at 68-73.

c. Operation and Maintenance

Operations and maintenance cost assumptions for the City's Greenfield operations are based upon benchmarking the operation of similar sized utilities on a per customer served basis (*see* Appendix C, Section VI.A at 133 National Public Utility O&M Benchmarking). However, it is assumed that, in the early years (team recommendations are until 2011), the City will outsource most required functions and the utility cost-basis serves as an effective proxy for competitive subcontract services.

The benchmarking studies reflect a high correlation of O&M costs, on a per customer basis, with the size of the given utility. The Greenfield utility business model projects customer populations beginning in 2006 of 4,017 increasing to 10,193 by 2023. As reflected in the study, the City's prospective Greenfield utility customer populations align with benchmark panel strata 5 and 6 (see Appendix C, Section VI.A at 133). Accordingly, Greenfield utility business model financial pro forma reflect annual O&M ranging from $478 to $333, per customer, depending upon customer populations.

d. Human Resource Requirements

The human resource requirements to operate the Greenfield utility distribution system present the City with two distinct options. The first is to develop and staff an organization capable of performing the required activities (construction,[26] maintenance, operation, customer service, and billing). The second option would be to outsource these functions. The MEU Study Team recommends, if the City pursues a business model consisting solely of a Greenfield utility, that the City outsource most of these functions for the first several years of operation. Alternatively, minimum staffing requirements are estimated as follows:

26 As described above, most of the necessary construction work on the electric distribution system will be performed by the developers and their contractors or subcontractors on a reimbursable basis.

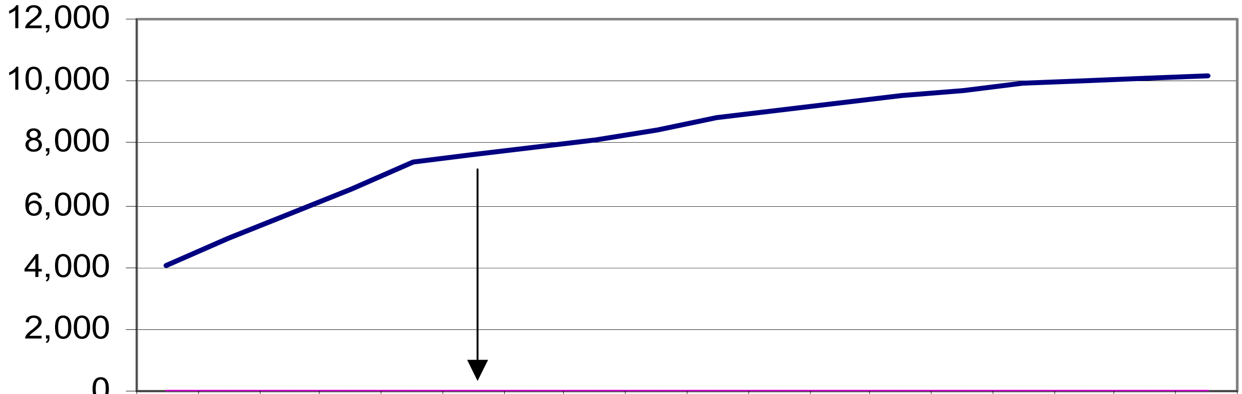
Greenfield Human Resource Requirements

Function	Number of Staff
Management	2
Distribution Engineering and Operation	12
Customer Service	6
Power Operations	2
Finance	1
Total	23

Based upon the projected buildout of the Greenfield development areas described in Section II, and the benchmark of utility personnel per 1,000 customers served as shown in the Appendix C , Section VI.B at 134, the minimum functional staff of twenty-three (23) would be justified in approximately 2011 (*see* Greenfield Area Projected Customer Population Chart below).

Prior to full operational status of the Greenfield option, the MEU Study Team recommends that the City staff this activity with a project manager and two distribution system engineers, and that the City time this staffing to coincide with the onset of the first Greenfield area development. Further, the City should rely on *objective* discipline area specialists to manage requisite subcontractor activities (RFPs, evaluation of bids, and selection of contractors).

Greenfield Areas Projected Customer Populations



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Customers	4,017	4,950	5,728	6,540	7,424	7,656	7,888	8,120	8,408	8,811	9,040	9,270	9,499	9,729	9,965	10,041	10,117	10,193
FTE	12	15	17	20	22	23	24	24	25	26	27	28	28	29	30	30	30	31

In addition to operating the distribution system, the operation of a Greenfield utility will require wholesale power procurement and scheduling. The MEU Study Team assumes the City will outsource most required functions, such as scheduling coordination (24-hour per day operation), trading, risk management, pre-scheduling, and real-time operations. However, the MEU Study Team has identified the following minimum functions which will need to be staffed:

Minimum Portfolio Operations - Greenfield

Function	Staff
Settlements	1
Procurement/Contracts	1
Rates	1
Credit	1
Management	1
	5

The cost to support these minimum requirements is estimated at $400,000 per year (see Appendix C, Section VI.D at 140). Wholesale power providers will support the remaining functions as part of a full-requirements service contract. The premium for these services can range between $5 and $10 per MWh depending upon the supplier and procurement volumes. To be conservative, the MEU Study Team adopted a projected cost of $10 per MWh.

Based upon this assumption and projected Greenfield utility energy requirements, it becomes less expensive to perform the services in-house in year 2011. In 2011 the minimum staffing costs identified above, escalated at 2.5% per year, are projected to be $452,000. Charges for the outsourced services are projected to reach $1.6 million in 2011, at that time the City should consider staffing all portfolio operations and scheduling positions.

3. Costs and Benefits

a. Financial Analyses

A financial analysis was performed in order to develop financial pro forma, which was then structured as consolidated statement of income for each MEU structure option. The consolidated statement based on the financial pro forma for the Greenfield option is located in this report in Appendix C, Section II.I at 92. As noted above, savings or potential income is the margin between current retail power costs, as provided by SDG&E, and the given MEU structure option's projected cost to provide the power. The MEU Study Team began its evaluation of each utility structural option with a planning horizon beginning in 2004 and then projected costs forward to 2023. Evolving legislation, regulation, implementation lead times and cost considerations caused the MEU Study Team to project MEU implementation beginning in 2006. The resulting study period was subsequently revised from 2006 to 2023 as reflected in the financial pro forma for each MEU structure option.

As a regulated public utility, SDG&E provides utility services at regulated cost-based rates. Hence, SDG&E's rates are directly tied to a demonstrated revenue requirement and its rate structures attempt to provide an equitable cost allocation among customer classes. The financial analysis provided herein compares SDG&E's revenue requirement with the revenue requirement of each MEU structure option to determine the City's potential savings or income. Pro forma summary tables compare each MEU structural option based on its relative ability to produce operational cost savings or benefits.

The Greenfield utility structure option financial analysis evaluates the costs and benefits for the City to take the following actions: 1) acquire development area distribution system infrastructure from developers (trenching, conduits and substructures); 2) subcontract the installation of high-voltage and other electrical components, and establish interconnection of the Greenfield distribution system; (3) procure and schedule energy to supply the needs of development occupants; 4) operate and maintain the Greenfield electric distribution system; and 5) provide retail customer service as required by Greenfield development area occupants.

b. Financial Analysis Structure

Greenfield utility customer population electric loads, evaluated under Section II.B at 9-11 and summarized above at 61-62, are applied to SDG&E current and projected generation rates to yield its revenue requirement or retail customer energy costs. Greenfield operating expenses are projected and subtracted from SDG&E's revenue requirement to yield the projected financial benefit. Elements contained in the analysis are summarized below:

- SDG&E Forecast Generation Rates[27]
  - Utility Retained Generation
  - Qualifying Facility Generation
  - Bilateral Power Purchase Contracts
  - CAISO charges
  - Residual Spot Market Purchases or Sales

- Greenfield Energy Cost (Commodity Costs)[28]
  - Spot Market Purchases
  - Power Purchase Contracts
  - Renewable Energy Contracts

- California Independent System Operator Charges (CAISO)[29]
  - Transmission
  - Ancillary Service
  - Grid Management
  - Reliability Services
  - Congestion Costs
  - Grid Operations
  - Unaccounted for Energy
  - Neutrality Adjustments
  - Deviation Charges

- Transmission and Scheduling Costs[30]
  - Scheduling and Settlements System

27 *See* Appendix C, Section II.A at 64-67.

28 *See* Appendix C, Section II.B.2 at 68-77

29 *See* Appendix C, Section II.D at 83-84.

30 *See* Appendix C, Section II.B.3 at 77-78.

-Procurement and Maintenance Costs
-Labor

- Non-Bypassable Charges[31]
  -CPUC Exit Fees
  Uneconomic Utility Retained Generation and Power Contracts
  DWR Power Purchase Contracts
  DWR Bond Charges - Financing Past Purchases

  -Other Non-Bypassable Charges
  Public Purpose Program Charges[32]
  Nuclear Decommissioning Charges
  Fixed Transition Amount Charges

- Distribution System Capital Cost[33]
  Costs Associated with Acquiring the Distribution System Assets

- Distribution System Operations and Maintenance Costs[34]

- In-Lieu Payments to Replace Lost Revenues[35]
  Lost or Reduced Franchise Fee Payments
  Lost or Reduced Property Tax Payments

c. Pro Forma Modeling Results

Total estimated costs of Greenfield operations are summarized in the table below for the Contracts Supply Strategy and are compared to projected SDG&E electric commodity related charges. The costs of Greenfield operations are broken out among the major cost of service elements. The most significant of these costs is the electric commodity costs. The

31 *See* Appendix C, Section II.C at 78-81.

32 Public Purpose Program Charges are included herein to support an evaluation of savings based on a comparison of baseline SDG&E customer bill charges and the charges customers would pay under this City MEU business model. However, revenue collected by the City associated with this charge would be available to the City to allocate to various activities that are identified in the Appendix C, Section II.C.2 at 81-82.

33 *See* Appendix C, Section II.E at 84-87.

34 *See* Appendix C, Section II.F at 87-88.

35 *See* Appendix C, Section II.H at 88-89.

commodity costs primarily reflect the long-term power purchase contracts that form the core of the supply portfolio, as well as the renewable energy contracts and spot market purchases.

The next largest cost category is transmission, operations and scheduling. One reason for the lack of early year savings for the Greenfield operation is the incurrence of start-up and fixed costs related to staffing the portfolio operations and scheduling coordinator functions. At start up, these costs must be spread over a relatively low volume of MWh sales. Lower costs could likely be achieved if the City outsourced these functions during the ramp-up stage of Greenfield operations. Potential outsourcing vendors include power marketers, scheduling coordinators, or consulting firms possessing the specialized knowledge and skill to enable them to perform these wholesale procurement functions. Such cost savings would very likely make the Greenfield operations revenue neutral or slightly positive during the initial years. As the load of the Greenfield operation grows, the City could then staff-up and perform these functions in-house.

Another major cost category relates to the non-bypassable charges or exit fees that SDG&E will impose on the Greenfield utility operation, pursuant to CPUC authority. Other significant costs include the financing charges for the Greenfield's distribution capital investments and distribution operations, which includes operations and maintenance, customer service and information (billing), and administrative and general expenses. Less significant costs include ancillary services and ISO charges and foregone franchise fee payments and in lieu payments for county property taxes.

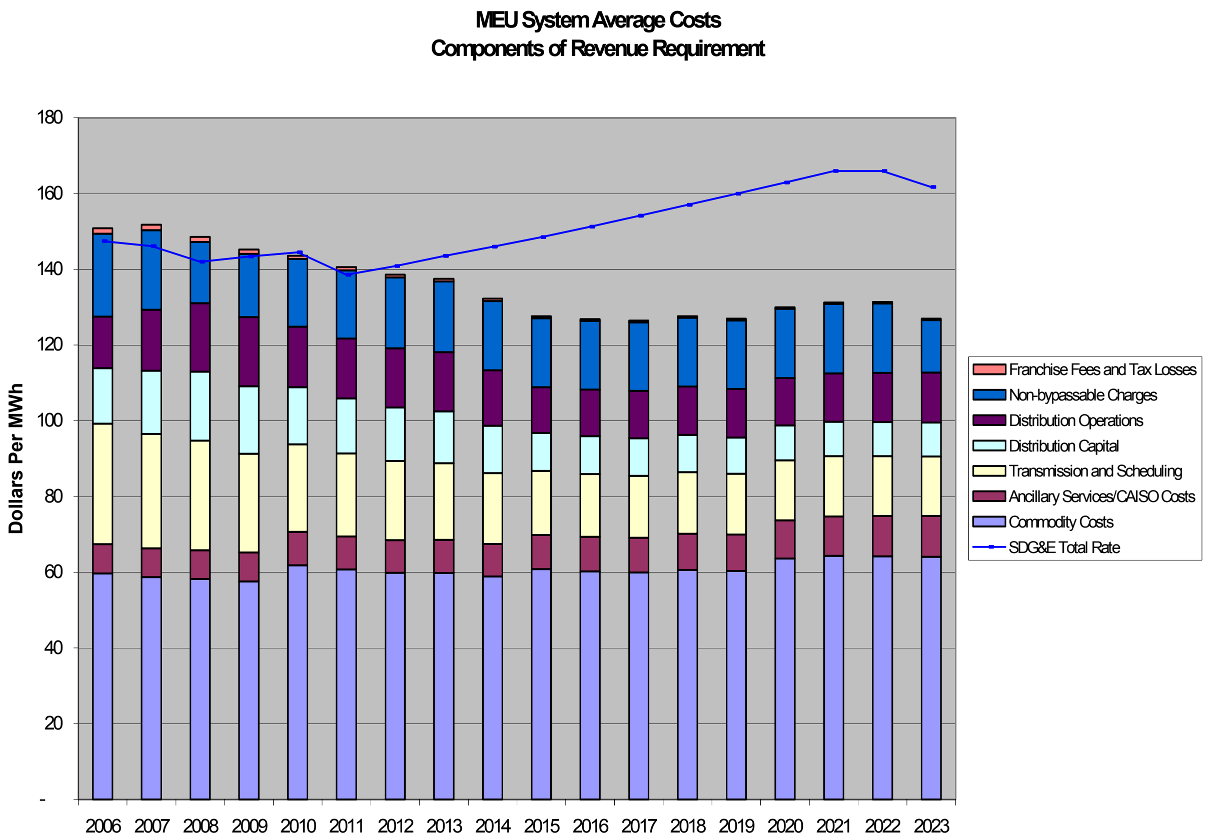
As stated earlier, savings are the difference between the Greenfield costs and the charges that SDG&E would collect through rates under the status quo retail electric arrangement. Persistent savings begin to occur in 2012 as the Greenfield load profile benefits from the addition of a larger number of electricity users. The addition of large commercial and industrial loads over time enables the distribution infrastructure to be used more intensively, lowering average costs and rates. The fixed costs of the distribution system and other fixed costs can be spread over a larger volume of electricity sales. However, the large savings shown to begin in 2015 should be interpreted with some caution due to the fact that an increasing proportion of high average use customers are projected for the Greenfield development, and these customers may require greater than average distribution infrastructure costs. A conservative conclusion would be that a Greenfield utility operation would lose money in the near term and commence producing savings in 2012. See chart below.

Pro Forma Summary and Projected Savings - Greenfield Contracts Supply Strategy
(Millions of Dollars Per Year)

Year	Commodity Costs	Ancillary Services/ISO Costs	Transmission & Scheduling	Non-Bypassable Charges	Distribution Capital	Distribution O&M	Franchise Fees/Taxes	Total Costs	SDG&E Charges	Savings
2006	5.2	0.7	2.8	1.9	1.3	1.2	0.1	13.3	13.0	(0.3)
2007	5.5	0.7	2.8	2.0	1.6	1.5	0.1	14.2	13.7	(0.5)
2008	5.8	0.8	2.9	1.6	1.8	1.8	0.1	14.7	14.1	(0.7)
2009	6.6	0.9	3.0	1.9	2.0	2.1	0.1	16.7	16.5	(0.2)
2010	9.5	1.3	3.5	2.7	2.3	2.4	0.1	22.0	22.1	0.1
2011	9.9	1.4	3.6	2.9	2.4	2.6	0.1	23.0	22.6	(0.3)
2012	10.4	1.5	3.6	3.2	2.4	2.7	0.1	24.1	24.5	0.4
2013	11.0	1.6	3.7	3.4	2.5	2.9	0.1	25.3	26.4	1.1
2014	12.3	1.8	3.9	3.8	2.6	3.1	0.1	27.5	30.4	2.9
2015	16.5	2.5	4.6	4.9	2.7	3.3	0.1	34.6	40.3	5.7
2016	16.9	2.5	4.7	5.1	2.8	3.4	0.1	35.5	42.4	6.8
2017	17.3	2.7	4.7	5.2	2.9	3.6	0.1	36.6	44.6	8.0
2018	18.1	2.8	4.9	5.4	2.9	3.8	0.1	38.1	46.8	8.8
2019	18.8	3.0	5.0	5.6	3.0	4.0	0.1	39.5	49.8	10.3
2020	21.3	3.4	5.3	6.1	3.1	4.2	0.1	43.5	54.5	11.0
2021	21.9	3.5	5.4	6.2	3.1	4.3	0.1	44.7	56.5	11.8
2022	22.2	3.7	5.5	6.3	3.1	4.5	0.1	45.5	57.4	12.0
2023	22.6	3.8	5.5	4.9	3.1	4.6	0.1	44.7	56.9	12.2

Chart 5 graphically compares the total Greenfield cost of service to the generation-related charges projected for SDG&E.

Chart 5: Comparison of Greenfield Costs Based on Contracts Supply Strategy



Pro forma detail for the Greenfield option is located in the accompanying Appendix C.[36]

d. Intangibles

(1) Benefits

Many of the benefits previously discussed under the CCA option would also apply with this utility structure, including the likelihood of lower-priced energy, local control, improved reliability, and economic development enhancements. An additional benefit of a

[36] *See* Appendix C, Section II.I at 92.

Greenfield municipalization effort would be that the City would not need to purchase the existing distribution facilities from SDG&E and go through a lengthy condemnation process.

(2) Risks

One of the impediments that would play out, at least through the initial infrastructure development period, is the economic viability of the program. Since at least part of the infrastructure would need to be in place before customers began to consume the energy, there would need to be enough working capital and cash flow to get through the first few years as development came "on-line." Construction of some distribution facilities such as line, poles, and extensions would be phased in as development progresses. However, some facilities may need to be constructed first, such as a substation with capacity to meet future load growth. Previous analysis and studies have shown that, if the load growth and development plan are well constructed, no more than a three-year "float" period should occur before energy revenue begins to pay for all related Greenfield start-up costs and operational expenses. Another major cost impediment is that the amount of energy required to serve the Greenfield utility operation starts out very small. Under those circumstances, the City may not be able to secure power at as competitive rates as it could if it was purchasing power to serve a larger load.

4. Legal/Regulatory

With the exception of rules requiring the payment of Cost Responsibility Surcharges, or "exit fees," discussed in Appendix B, Section II.C.4 at 35-39, there are no specific state laws or Commission rules regulating the implementation of the Greenfield development option. Furthermore, such implementation is not restricted by the terms of the Chula Vista City Charter, and the City has adequate authority under the California Constitution and state statutes to provide electric service to its inhabitants. Federal law governs the interconnection of the city-owned distribution facilities with the facilities of SDG&E and the CAISO. The law regarding interconnection requirements is also addressed in Appendix B, Section II.C.3 at 33-35.

5. Financing Options

Implementation of a Greenfield Utility will require a significant initial capital investment, as well as ongoing annual capital investments. The investment will be mainly for distribution plant, including physical distribution equipment, associated equipment required for maintenance, and computer hardware and software. Assuming an initial Greenfield utility with approximately 4,000 customers, the start-up capital costs are estimated at $13.8 million. Annual debt service to support the initial investment would be approximately $1.3 million at an assumed tax-exempt debt interest rate of 5.5% (amortization period 30-years). Annual debt service requirements would increase over time as additional Greenfield areas are developed, as shown in the financial pro forma results.

The City would have a variety of financing mechanisms available to finance its Greenfield projects depending upon the specific asset to be required or built and/or activity. Financing techniques might include the following:

- General Obligation Bonds
- Limited Obligation Bonds
- Special Assessment
- Certificates of Participation
- Revenue Bonds
- Commercial Paper

In Appendix C, Section IV.A, at 126-27, the MEU Study Team has provided an overview and comparative analysis of each type of financing vehicle that is available to the City.

6. Implementation Schedule

a. Major and Critical Steps

(1) Ordinance:

City passes an ordinance to form a municipal utility (City has already passed Ordinance No. 2835).

(2) System Design:

Electric distribution design firms will work with developers to design and specify system requirements in compliance with applicable design standards to serve the planned development. (2-3 mo.)

(3) Determine Interconnection Requirements:

Assess technical requirements and cost to achieve interconnection of the development distribution system with adjacent transmission or distribution facilities. If the given Greenfield development is going to be interconnected with facilities operating below transmission system voltage levels (which for SDG&E is 138kV), and served at distribution voltage levels (most likely 12-69 kV), it will need to be served under SDG&E's WDAT. If this is the case, the City must complete an application for service according to the SDG&E WDAT.[37] SDG&E will perform a

[37] A copy of the SDG&E WDAT is attached in Appendix D.

facilities requirement and system impact study to determine the logistics and the cost to implement an interconnection with the SDG&E system. A successful application will result in the execution of a service agreement which sets forth the costs, terms and conditions of service. (6-9 mo.)

(4) Final Evaluation:

Evaluate and assess projected loads, costs and benefits (at this point, primarily interconnection costs) and determine whether to proceed with the project. (1 mo.)

(5) Procure and Schedule Power:

Based on load studies and forecasts derived from information provided under item (2), tailor and initiate a resource and schedule power delivery to coincide with project completion and estimated development occupancy. Update power delivery schedules, as required before operational status as provided in power contract terms and conditions, to balance loads and resources. (2 mo.)

(6) Staffing/Outsourcing:

Initiate human resources plan. Update plans to reflect development schedules and requirements; perform staffing or solicit outsource staffing services. (2 mo.)

(7) Infrastructure Construction:

Land developer subcontractors will install electric system infrastructure, including trenching, conduit, backfill, vaults, manholes and transformer pads (as they would if SDG&E were to serve the area). (2-5 weeks)

(8) High Voltage Equipment Installation:

The City will engage subcontractors specializing in high-voltage interconnection to pull conductors through the conduit, install substations, connectors, switches, transformers and connections with metered panels (residents, businesses, etc). (2-3 weeks)

(9) Peripheral Equipment:

City will install peripheral electrical equipment (traffic controllers/irrigation pedestals/street lights). (2-3 weeks)

(10) Initiate Operations:

Schedule and initiate Greenfield utility operations to coincide with the occupancy date for newly developed area. (1 mo. - occupancy date)

b. Timelines

The MEU Study Team estimates that the steps identified above would take between 15 and 20 months to complete from the time electric distribution system design firms begin working with developers. Operation of a new Greenfield utility project will depend upon actual project completion and building occupancy in the newly developed area. The project implementation schedule Gantt chart, Section V.C at 168 and Appendix C, Section II.V.B at 131, is structured in months from the onset of any given Greenfield development project.

7. Recommendation

The MEU Study Team recommends that the City immediately commence the implementation of Steps 6 (a)(2) through (10) above to enable the City to commence providing electric utility services through Greenfield utility projects in the developing areas of Mid-Bayfront, Otay Ranch and Sunbow Planning area. Establishment and operation of Greenfield utility projects in newly developed areas within the City will provide a vehicle for the City to establish an operating electric utility and to gain the experience and staffing necessary to combine its Greenfield utility operations with its CCA program (see discussion in Section E below) and, eventually, to acquire and operate a full service municipal electric distribution system (see discussion in Section F below).

E. Combined Community Choice Aggregation/Greenfield Development

As identified in Section III.B, the MEU Study Team's analysis demonstrates that the City can obtain the greatest potential benefit by forming a CCA and simultaneously pursuing Greenfield project opportunities. Ideally, the City would acquire equity in a generation project within the City to supply the combined CCA/Greenfield loads. A CCA program would give the City the operational scale required to efficiently source electricity for the CCA *and* Greenfield customers and compete successfully with the electric supply portfolio of SDG&E.

The Greenfield utility option, in and of itself, is not of a sufficient size to support the development of a cost-effective generation project. However, implementing the combination of CCA and Greenfield options would capture the benefits of CCA in areas where there is an SDG&E distribution infrastructure. This would produce commensurate levels of savings on the electric energy commodity component for Greenfield areas and significantly increase Greenfield project cost-effectiveness.

In this scenario, the City would implement a city-wide CCA program concurrent with efforts to begin distribution utility operations in Greenfield development areas. The City would supply electricity to all electric customers within the City[38] and distribute electricity to electric customers within the Greenfield development areas.

For non-Greenfield areas, the City would procure electric supply for customers of the CCA, and SDG&E would continue to deliver the electricity to end use customers over distribution facilities owned and operated by SDG&E. Customers would pay SDG&E the retail rate for non-generation charges (e.g., transmission and distribution) as they do today. SDG&E would provide a credit on the bill to remove its costs related to generation and procurement of electricity that would be procured by the CCA. The bill credit that SDG&E will provide for generation-related charges is assumed to be the entire generation rate, net of the applicable exit fees. SDG&E would continue to perform metering and billing services for end use customers, the costs of which are bundled within existing retail distribution rates.

For the Greenfield development areas, the City would take wholesale transmission service from SDG&E and the CAISO, and its customers in the Greenfield development area would no longer pay SDG&E electricity retail rates. Once the Greenfield development is interconnected to SDG&E's distribution system, the City would take service under SDG&E's WDAT.

The cost for taking wholesale distribution service under the WDAT would be determined by SDG&E based on an assessment of the actual distribution facilities utilized by the

[38] Except those that "opt out" under the CCA option. In studying this option, the MEU Study Team assumed 100% participation in the CCA program.

City. SDG&E would perform a study to determine the allocated portion of pre-existing facilities that should be assigned to serve the Greenfield utility, as well as any new facilities required to interconnect the Greenfield utility. It would then apply a fixed carrying charge percentage to determine an annual revenue requirement and monthly demand charge for the distribution facilities. The fixed carrying charge is derived to recover SDG&E's cost of capital, depreciation, operations and maintenance expenses, and tax expenses related to the facilities. The monthly demand charge would be applied to the monthly kW demand recorded at the meter at the interconnection point between the Greenfield distribution system and SDG&E's system.

The City, or its customers, would be subject to the payment of the exit fees and other non-bypassable charges mandated by AB 1890 and CPUC orders. [39] The distribution capital costs associated with City-owned distribution system serving the Greenfield development will be determined based on the cost to construct the required new facilities.

1. Customer Base

A CCA program would encompass all electric customers within the City boundaries, except those in the Greenfield development areas and those who have notified the City of their desire to opt out of the CCA program and continue to receive electric commodity supply service from SDG&E. As mentioned above, the feasibility analysis assumes 100% participation in the CCA program. The chart below is based on the same assumption. Section II describes in detail the customer and load projections used in the analysis, and these are summarized in the following table. The customer base is shown below for the CCA program, with the loads of the Greenfield development customers removed.

[39] *See* Appendix C, Section II.C at 78-81.

CCA Projected Customers, MWh, And Peak MW By Year, Excluding Greenfield Customers

Year	Customers	MWh	Peak MW
2006	82,635	774,323	131
2007	84,462	792,524	134
2008	86,032	809,730	137
2009	87,608	827,266	140
2010	88,313	841,550	143
2011	88,911	851,778	145
2012	89,515	862,159	146
2013	90,124	872,697	148
2014	90,738	883,393	150
2015	91,218	895,478	153
2016	91,698	907,742	155
2017	92,180	920,188	157
2018	92,662	932,817	160
2019	93,145	945,633	162
2020	93,624	958,439	164
2021	93,840	969,808	166
2022	94,058	981,323	168
2023	94,276	992,986	170

This chart assumes that all customers in newly developed areas will be served as Greenfield project customers and that CCA projected customers will be limited to areas now served by SDG&E.

A Greenfield operation would encompass all future electric customers within newly developing areas of the City. Section II.B at 9-17 describes in detail the customer and load projections used in the analysis, and these are summarized in the following table.

Greenfield Projected Customers, MWh, And Peak MW By Year

Year	Customers	MWh	Peak MW
2006	4,017	87,863	16
2007	4,950	93,849	17
2008	5,728	99,172	18
2009	6,540	114,759	20
2010	7,424	152,996	27
2011	7,656	163,334	29
2012	7,888	173,713	31
2013	8,120	184,132	33
2014	8,408	208,090	37
2015	8,811	271,149	48
2016	9,040	280,195	50
2017	9,270	289,286	52
2018	9,499	298,422	53
2019	9,729	311,332	55
2020	9,965	334,685	60
2021	10,041	340,374	61
2022	10,117	346,161	62
2023	10,193	352,046	63

2. Functional Elements

a. Infrastructure Requirements

(1) CCA Infrastructure

The infrastructure requirements for the development of a CCA program is fully discussed and set forth in Section IV.C.2.a above at 40 and will not be repeated herein.

(2) Greenfield Infrastructure

(a) Distribution System Infrastructure

The Distribution System Infrastructure necessary to implement a Greenfield development project is fully described and set out in Section IV.D.2.a(1) above at 62 and will not be repeated herein.

(b) Interconnection/WDAT Costs

The wholesale distribution costs which would be imposed pursuant to the SDG&E WDAT are fully described and set out in Section IV.D.2.a (2) above at 64 and will not be repeated herein.

b. Resource Management

An advantage of pursuing the Greenfield option in conjunction with the CCA option is that the larger combined customer loads provide critical mass and would enable the City to pursue generation ownership as a feasible supply option. Internal generation would minimize the total electric supply costs of the combined CCA/Greenfield operation for several reasons. First, the production costs of a new Combined Cycle Gas Turbine are expected to be below market-clearing prices. In essence, the CCA/Greenfield option would allow the City to capture generation profits within the CCA/Greenfield operation. In addition, generation located within the City boundaries would enable the City to avoid paying transmission congestion charges, which are assessed by the CAISO for use of the transmission grid when congestion is present. Electricity obtained via power purchase contracts may or may not be subject to charges for transmission congestion, depending on whether the point of delivery specified in the contract would require the use of the CAISO-controlled transmission grid.

For CCA customers, the transmission charges for the fixed costs of the transmission network, as opposed to transmission congestion charges, are not impacted by the location of the generator due to the fact that, under CCA, the retail transmission rates of SDG&E will continue to apply.

For Greenfield areas, internal generation would minimize wholesale transmission charges and other charges assessed by the CAISO. So long as the internal generator operates at a capacity factor greater than 50%,[40] FERC rules require transmission access charges to be assessed on a net load basis, i.e., the internal generation is subtracted from the gross load requirements of the Greenfield utility before applying the transmission rates. In addition, internal generation reduces the exposure to charges for reliability services and certain elements of the CAISO's grid management charge.

These wholesale transmission related benefits would not be obtained if the City were to supply its load through power purchase contracts or ownership of remote generation that

[40] Capacity factor is a measure of utilization for a power plant. A plant with a maximum generating capacity of 130 MW would have to produce at least 47,450 MWh in a month (130 MW x 730 hours x 50%) in order to obtain a capacity factor of at least 50%.

must utilize the CAISO-controlled transmission network for delivery to the CCA/Greenfield utility.

The MEU Study Team has modeled generation options for the City using operating and cost parameters of a new combined cycle gas turbine operating as a base load plant. These parameters include the unit's heat rate, capacity cost, variable O&M costs,[41] availability factor, hours of planned operation, and the year the resource becomes operational. Sales of any excess production beyond what is needed to serve the City's load could be sold into the market. The price for excess sales reflects a 25% discount relative to the prevailing peak or off-peak price to reflect the probability that excess sales will occur during the lowest priced hours of the on- or off-peak periods.

The following assumptions were used in the calculation of generation costs:

Capacity:	130 MW
Technology:	Combined Cycle Natural Gas Turbine
Year Online:	2006
Heat Rate:	7,000 BTU/KWh
Capacity Factor:	90%
Variable O&M:	$2 Per MWh
Excess Sales:	75% of Market Price

The Contracts supply portfolio evaluated for the CCA/Greenfield option includes the following fixed priced contracts.

Power Purchase Contracts – CCA/Greenfield Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	50	49	5 Years
2006	Peak (6 x 16)	75	59	5 Years
2011	Base (7 x 24)	50	51	5 Years
2011	Peak (6 x 16)	75	61	5 Years
2016	Base (7 x 24)	75	51	5 Years
2016	Peak (6 x 16)	100	61	5 Years
2021	Base (7 x 24)	75	55	3 Years
2021	Peak (6 x 16)	125	66	3 Years

41 See discussion in Section II.C.1 at 21-22.

The following renewable energy contracts were assumed in the MEU portfolios for both the Generation and Contracts Supply Strategies:

Renewable Energy Contracts - CCA/Greenfield Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	7	52	1 Year
2007	Base (7 x 24)	8	51	1 Year
2008	Base (7 x 24)	10	52	1 Year
2009	Base (7 x 24)	11	52	1 Year
2010	Base (7 x 24)	13	52	1 Year
2011	Base (7 x 24)	15	53	1 Year
2012	Base (7 x 24)	17	54	1 Year
2013	Base (7 x 24)	18	54	1 Year
2014	Base (7 x 24)	20	54	1 Year
2015	Base (7 x 24)	23	54	1 Year
2016	Base (7 x 24)	25	53	1 Year
2017	Base (7 x 24)	28	53	1 Year
2018	Base (7 x 24)	29	55	3 Years
2021	Base (7 x 24)	30	58	3 Years

Additional details regarding the power supply portfolios modeled for the City are included in the Appendix C, Section II.B.2 at 68-77.

c. Operations and Maintenance

(1) Operations and Maintenance CCA

The operations and maintenance requirements for a CCA program, modeling projected costs, are discussed and set forth in Section IV.C.2.c at 44 and will not be repeated herein.

(2) Operations and Maintenance Greenfield

The operation and maintenance requirements for a Greenfield development project, including projected costs, are discussed and set forth in Section IV.D.2.c at 67 and will not be repeated herein.

d. Human Resource Requirements

(1) Human Resource Requirements - CCA

The human resource requirements for a CCA program, including both in-house personnel and outsourcing, are discussed and set forth in Section IV.C.2.d at 44 and will not be repeated herein.

(2) Human Resource Requirements - Greenfield

The human resource requirements for a Greenfield Utility, including projected costs to operate the distribution system, are discussed in Section IV.D.2.d at 44-45 and are not repeated herein. The human resource requirements to perform wholesale power procurement, including the need to outsource related functions, would no longer be required of the Greenfield utility operation and can be performed by CCA portfolio operations and scheduling personnel. This reduces the Greenfield utility staffing and operational costs by between $1.2 and $2.0 million per year, as reflected in the financial pro forma.

3. Costs and Benefits

a. Financial Analysis

The financial analysis for the CCA option is set forth in Section IV.C.3.a at 45-46 above. The financial analysis for the Greenfield option is set forth in Section IV.D.3.a at 70 above.

b. Financial Analysis Structure

CCA and Greenfield customer population electric loads, evaluated under Section II.B at 9-16 and summarized above at 81-83, are applied to SDG&E current and projected generation rates to yield the City's revenue requirement or retail customer energy costs. CCA and Greenfield operating expenses are projected and subtracted from SDG&E's revenue requirement to arrive at the projected financial benefits for the City. Elements contained in the analysis are summarized below:

➢ <u>SDG&E Forecast Generation Rates</u>[42]
- Utility Retained Generation
- Qualifying Facility Generation
- Bilateral Power Purchase Contracts
- CAISO charges

[42] *See* Appendix C, Section II.A at 64-67.

- Residual Spot Market Purchases or Sales

- CCA and Greenfield Energy Cost (Commodity Costs)[43]
  - Spot Market Purchases
  - Power Purchase Contracts
  - Renewable Energy Contracts
  - Generation Ownership

- California Independent System Operator Charges charges (CAISO)[44]
  Ancillary Service
  Grid Management
  Reliability Services
  Congestion Costs
  Grid Operations
  Unaccounted for Energy
  Neutrality Adjustments
  Deviation Charges

- Transmission and Scheduling Costs[45]
  Scheduling and Settlements System
  Procurement and Maintenance Costs
  Labor

- Non-Bypassable Charges[46]
  -CPUC Exit Fees
    Uneconomic Utility Retained Generation and Power Contracts
    DWR Power Purchase Contracts
    DWR Bond Charges - Financing Past Purchases
  -Other Non-Bypassable Charges (applies to Greenfield portion only)
    Public Purpose Program Charges[47]

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43 *See* Appendix C, Section II.B.2 at 68-77.

44 *See* Appendix C, Section II.D at 83-84.

45 *See* Appendix C, Section II.B.3 at 77-78.

46 *See* Appendix C, Section II.C at 78-81.

47 Public Purpose Program Charges are included herein to support an evaluation of savings based on a comparison of baseline SDG&E customer bill charges and the charges customers would pay under this City MEU business model. However, revenue collected by the City associated with this charge would be available to the City to allocate to various activities that are identified in Appendix C, Section II.C.2 at 81-82.

Nuclear Decommissioning Charges
Fixed Transition Amount Charges

- Greenfield Distribution System Capital Cost[48]
  Costs Associated with Acquiring the Distribution System Assets

- Greenfield Distribution System Operations and Maintenance Costs[49]

- Greenfield In-Lieu Payments to Replace Lost Revenues[50]
  Lost or Reduced Franchise Fee Payments
  Lost or Reduced Property Tax Payments

The hybrid CCA/Greenfield business model cost benefits are assessed based upon two energy supply strategies. In the first supply strategy, it is assumed the City's MEU will take an ownership position in a power generation facility (Generation Supply Strategy). In the second, it is assumed the City's MEU will purchase all of its energy requirements in the wholesale energy market by executing power contracts with suppliers (Contracts Supply Strategy).

Power costs are allocated to resource supply options for the given supply strategy as follows:

48 *See* Appendix C, Section II.E at 84-87.

49 *See* Appendix C, Section II.F at 87-88.

50 *See* Appendix C, Section II.H at 88-89.

2006 Energy Resource Costs ($) by Supply Strategy

Greenfield Areas

	Generation		Contracts	
Market Purchases	$106,014	2.3%	$92,684	1.6%
Contracts	$455,520	10.0%	$5,594,200	98.4%
Power Production	$3,983,306	87.6%		
	$4,544,840		$5,686,884	

CCA Areas

	Generation		Contracts	
Market Purchases	$4,382,988	11.1%	$3,069,022	6.9%
Contracts	$2,733,120	6.9%	$41,500,040	93.1%
Power Production	$32,532,245	82.1%		
	$39,648,353		$44,569,062	

Generation Strategy - Major Capital Expenditures:

Implementing a CCA/Greenfield business model with the Generation Supply Strategy requires acquiring an interest in a generation project. The Generation Supply Strategy would require an initial capital expenditure estimated at $78 million. This figure is derived based on an assumed ownership of 130 MW at an installed capital cost of $600,000 per MW. Annual debt service to support this investment would be approximately $5.4 million at an assumed tax-exempt debt interest rate of 5.5%. This cost, as well as generation facility operations and maintenance and fuel cost, is included in the Pro Forma Table at 92 below under "Commodity Costs" and in Appendix C, Section II.I at 93 and 94, Section V. Operating Expenses, (A)(iii) Power Production.

c. Pro Forma Results

Financial pro forma results were prepared for the CCA/Greenfield option with both supply strategies. *See* Appendix C, Section II.I at 93-96.

(1) CCA/Greenfield - Generation

Total estimated costs of the CCA/Greenfield combined option are summarized in the table below for the Generation Supply Strategy and compared to projected SDG&E electric commodity charges. The costs of CCA/Greenfield operations are broken out among the major cost of service elements. The most significant of these is the electric commodity costs, which consist primarily of the capital and operating costs of the CCA/Greenfield's generator, plus renewable energy contract costs and spot market purchases. The next largest cost category is the non-bypassable charges or exit fees that SDG&E will impose on the CCA/Greenfield operation, pursuant to CPUC authority.

Other significant costs include transmission, operations, and scheduling, ancillary service, CAISO charges, financing charges for the Greenfield distribution capital investments, and distribution operations, which includes operations and maintenance, customer service and information (billing), and administrative and general expenses. Less significant costs include foregone franchise fee payments and in lieu payments for county property taxes related to the Greenfield facilities.

Savings represent the difference between the CCA/Greenfield costs and the charges that SDG&E would have collected through rates under the status quo retail electric service arrangements. Significant savings are projected to occur in every year of the study period as shown on the following chart.

Pro Forma Summary and Projected Savings - Combined CCA/Greenfield Generation Supply Strategy
(Millions of Dollars Per Year)

Year	Commodity Costs	Ancillary Services/ISO Costs	Transmission & Scheduling	Non-bypassable Charges	Distribution Capital	Distribution O&M	Franchise Fees/Taxes	Total Costs	SDG&E Charges	Savings
2006	44.2	2.4	4.2	10.6	1.3	1.2	0.1	64.0	78.9	14.9
2007	44.3	2.5	4.3	10.0	1.6	1.5	0.1	64.3	79.1	14.7
2008	46.6	2.7	4.4	8.4	1.8	1.8	0.1	65.8	78.8	13.0
2009	48.7	3.0	4.5	9.3	2.0	2.1	0.1	69.8	83.0	13.3
2010	51.6	3.4	4.8	10.8	2.3	2.4	0.1	75.5	90.1	14.6
2011	53.5	3.6	5.0	11.4	2.4	2.6	0.1	78.5	85.6	7.0
2012	55.5	3.8	5.1	12.5	2.4	2.7	0.1	82.2	89.4	7.3
2013	56.5	4.0	5.2	12.9	2.5	2.9	0.1	84.1	93.8	9.7
2014	58.7	4.3	5.4	13.2	2.6	3.1	0.1	87.4	100.0	12.5
2015	63.1	5.0	6.0	14.4	2.7	3.3	0.1	94.6	112.4	17.8
2016	63.5	5.2	6.1	14.7	2.8	3.4	0.1	95.9	117.2	21.3
2017	64.5	5.4	6.3	14.9	2.9	3.6	0.1	97.7	122.2	24.4
2018	67.5	5.7	6.4	15.3	2.9	3.8	0.1	101.8	127.3	25.6
2019	69.9	6.1	6.6	15.6	3.0	4.0	0.1	105.3	133.3	28.0
2020	72.6	6.5	6.8	16.2	3.1	4.2	0.1	109.6	141.1	31.5
2021	75.8	6.9	6.9	16.4	3.1	4.3	0.1	113.6	146.1	32.6
2022	78.7	7.2	7.0	16.7	3.1	4.5	0.1	117.3	148.1	30.8
2023	79.1	7.4	7.2	11.2	3.1	4.6	0.1	112.7	144.5	31.7

(2) CCA/Greenfield - Contracts

The total estimated costs of the CCA/Greenfield combined option are summarized below for the Contracts Supply Strategy and compared to projected SDG&E electric commodity charges. The costs of CCA/Greenfield operations are broken out among the major cost of service elements. The most significant of these is the electric commodity costs. The commodity costs primarily reflect the long-term power purchase contracts that form the core of the supply portfolio, as well as the renewable energy contracts and spot market purchases. The next largest cost category includes the non-bypassable charges or exit fees that SDG&E will impose on the CCA/Greenfield operation, pursuant to CPUC authority.

Other significant costs include transmission, operations, and scheduling, ancillary service, CAISO charges, financing charges for the Greenfield distribution capital investments, and distribution operations, which includes operations and maintenance, customer service and information (billing), and administrative and general expenses. Less significant costs include foregone franchise fee payments and in lieu payments for county property taxes related to the Greenfield facilities.

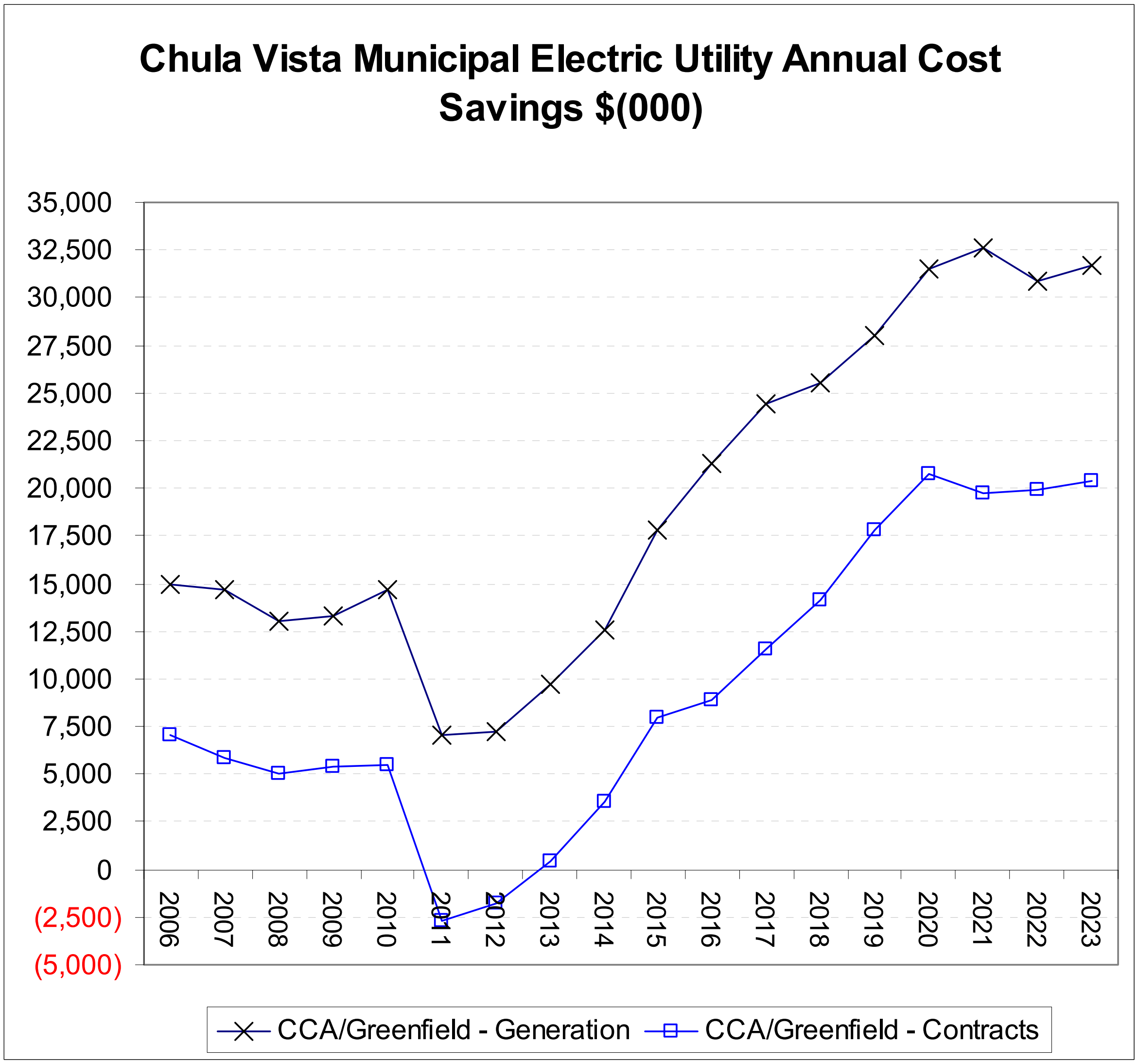
Significant savings are projected to occur in all but two years of the study period. Projected SDG&E rate reductions in 2011, resulting from the expiration of DWR power purchase contracts, would eliminate any savings until 2013. At that time, annual increases in SDG&E rates, combined with the cost efficiencies gained from the addition of more or larger customers to the overall Greenfield customer mix are projected to provide persistent savings opportunities for the City as shown on the chart below.

Pro Forma Summary and Projected Savings - Combined CCA/Greenfield Contracts Supply Strategy
(Millions of Dollars Per Year)

Year	Commodity Costs	Ancillary Services/ISO Costs	Transmission & Scheduling	Non-bypassable Charges	Distribution Capital	Distribution O&M	Franchise Fees/Taxes	Total Costs	SDG&E Charges	Savings
2006	49.7	4.2	4.7	10.6	1.3	1.2	0.1	71.9	78.9	7.1
2007	50.8	4.3	4.8	10.0	1.6	1.5	0.1	73.2	79.1	5.9
2008	52.2	4.5	4.9	8.4	1.8	1.8	0.1	73.8	78.8	5.0
2009	54.1	4.8	5.1	9.4	2.0	2.1	0.1	77.6	83.0	5.4
2010	57.8	5.4	5.6	11.0	2.3	2.4	0.1	84.7	90.1	5.5
2011	60.3	5.6	5.7	11.6	2.4	2.6	0.1	88.3	85.6	(2.7)
2012	61.7	5.8	5.8	12.6	2.4	2.7	0.1	91.2	89.4	(1.8)
2013	62.9	6.1	5.9	13.0	2.5	2.9	0.1	93.3	93.8	0.4
2014	64.8	6.4	6.1	13.3	2.6	3.1	0.1	96.4	100.0	3.6
2015	69.8	7.2	6.8	14.5	2.7	3.3	0.1	104.4	112.4	8.0
2016	72.6	7.6	6.9	14.8	2.8	3.4	0.1	108.3	117.2	8.9
2017	74.0	7.8	7.0	15.1	2.9	3.6	0.1	110.6	122.2	11.6
2018	75.5	8.2	7.2	15.4	2.9	3.8	0.1	113.2	127.3	14.2
2019	76.7	8.6	7.3	15.8	3.0	4.0	0.1	115.5	133.3	17.8
2020	79.8	9.1	7.7	16.4	3.1	4.2	0.1	120.4	141.1	20.7
2021	85.0	9.4	7.8	16.6	3.1	4.3	0.1	126.4	146.1	19.8
2022	85.9	9.8	7.9	16.8	3.1	4.5	0.1	128.2	148.1	19.9
2023	86.8	10.0	8.0	11.3	3.1	4.6	0.1	124.1	144.5	20.4

Pro forma detail for the CCA/Greenfield option is located in the accompanying Appendix C, Section II.I at 93-96.

The following chart demonstrates that the adoption of a Generation Supply Strategy would result in substantially greater benefits than the Contracts Supply Strategy if the City implements a combined CCA/Greenfield option:



4. Legal/Regulatory

Pursuing a program which combines both Greenfield development and a CCA program will not alter the legal requirements for either option. There are no legal impediments (or advantages) to pursuing both options simultaneously or in tandem.

5. Financing Options

a. CCA Financing

Implementing a CCA program would not require major capital outlays, with the possible exception of capital required for generation acquisition. Acquiring interest in a generation project to support the Generation Supply Strategy would require initial capital expenditures estimated at $78 million. This figure is derived based on an assumed ownership of 130 MW at an installed capital cost of $600,000 per MW. Annual debt service to support this investment would be approximately $5.4 million at an assumed tax-exempt debt interest rate of 5.5%.

b. Greenfield Financing

Implementation of Greenfield projects will require a significant initial capital investment, as well as ongoing annual capital investment. The investment will be mainly for distribution plant for physical distribution equipment, associated equipment required for maintenance, and computer hardware and software. Assuming an initial Greenfield development with approximately 4,000 customers, start-up capital costs are estimated at $13.8 million. Annual debt service to support the initial investment would be approximately $1.3 million at an assumed tax-exempt debt interest rate of 5.5%. Annual debt service requirements would increase over time as additional Greenfield areas are developed, as shown in the financial pro forma results.

c. Methods of Financing

The City would have a variety of financing mechanisms available to finance its MEU projects depending upon the specific asset and/or activity. Financing techniques might include the following:

- General Obligation Bonds
- Limited Obligation Bonds
- Special Assessment
- Certificates of Participation
- Revenue Bonds
- Commercial Paper

In Appendix C, Section IV.A at 126-27, the MEU Study Team has provided an overview and comparative analysis of each type of financing vehicle that is available to the City.

6. Implementation Schedule

a. Major and Critical Steps

The major and critical steps to implement a CCA project are discussed and outlined in Section IV.C.6.a at 58-60 and will not be repeated herein. The major and critical steps to implement a Greenfield project are discussed and outlined in Section IV.D.6(2) at 77-79 and will not be repeated herein. Suffice it to say that, in combining the Greenfield and CCA options, the critical steps and timing will remain relatively unchanged.

b. Timelines

The implementation schedules for the CCA and Greenfield MEU options can move forward simultaneously and the two options can be implemented on approximately the same schedule depending on separate variables.

In the case of the CCA option, the largest unknown is the development and implementation of final CCA rules and regulations by the CPUC. As discussed earlier, the CPUC initiated its CCA rulemaking procedure on August 21, 2003 and issued Rulemaking No. R-03-09-007 on September 4, 2003. On October 2, 2003, the CPUC reissued the rulemaking under Docket No. R.03-10-003 and an initial pre-hearing conference and a workshop have been held. It is anticipated that final CCA rules and regulations will be implemented by mid-2004, and, under this schedule, the MEU Study Team estimates that a CCA program could be operational by mid-2005. (Please refer to Section V.C at 167 and Appendix C, Section V.A at 130 for Gantt chart time requirement projection for each critical path necessary to form a CCA.)

In the case of a Greenfield Project, the operation of any Greenfield Project will depend upon actual project completion and building occupancy in the newly developed areas designated for Greenfield development. The MEU Study Team estimates that the steps necessary to implement a Greenfield Project would take from 15 to 20 months to complete from the time the City Staff and an electric distribution design firm begin working with the developers of the Greenfield areas. The project implementation schedule (Gantt Chart) in Section V.C at 169 and Appendix C, Section V.B at 131, is structured in months from the onset of any given Greenfield development project.

7. Recommendation

The detailed economic and financial analysis performed by the MEU Study Team demonstrates that the City can obtain the greatest potential benefit in the short term by forming a CCA and simultaneously pursuing Greenfield project opportunities. Under the most beneficial option, the City would build or acquire equity in a generation project (130 MW) within the City to supply the combined CCA/Greenfield loads. The CCA program would give the City the operational scale required to effectively source electricity for the CCA and Greenfield customers and successfully compete with the electric supply portfolio of SDG&E.

Based on the financial pro forma performed by the MEU Study Team, the combined CCA/Greenfield utility option, using in-City generation would produce savings amounting to $14.9 million in 2006 and increase to $31.7 million in 2023 (again with significant reductions in savings in the 2011-2014 time frame).

The MEU Study Team strongly recommends that the City implement the combined CCA/Greenfield utility option in the immediate future. The MEU Study Team estimates that a CCA program would be operational by mid-2005 (assuming that the CPUC issues final rules and regulations by mid-2004). With respect to Greenfield development, the MEU Study Team estimates that the initial Greenfield project could be implemented in a 15 to 20 month time frame depending upon the construction schedule and building occupancy within the designated Greenfield areas. Thus, a combined CCA/Greenfield operation could be implemented as early as 2006.

F. Municipal Distribution Utility

Under the Municipal Distribution Utility (MDU) option, the City would acquire, by negotiation or through the exercise of eminent domain, the electric distribution facilities of SDG&E within the City's boundaries. The MDU would provide retail electric service to all customers within the City after interconnecting its distribution system with SDG&E and establishing an electric resource portfolio by installing generation facilities, through power purchases from California electric markets, or a combination of internal generation and purchased power contracts.

To the extent that the City relies on purchases from other suppliers, the MDU would take wholesale transmission service from SDG&E under SDG&E's WDAT, which defines the applicable charges and terms and conditions of transmission service and customers would no longer pay SDG&E's retail rates.

Once the City elects to acquire the SDG&E distribution system, SDG&E would be required to perform a study to determine the cost of any reconfiguration of the SDG&E system in order to separate and interconnect the MDU system with the remaining SDG&E system. The FERC would, in the event of a dispute, determine the terms and conditions of the interconnection of the MDU with the SDG&E transmission system and the interconnection and related costs would be directly assigned to the MDU.

If the City and SDG&E cannot agree on the terms and conditions of the acquisition, including the pricing of the distribution system, the City will be required to initiate and prosecute the condemnation of SDG&E distribution system and allow the condemnation court (or, alternatively, the CPUC) to determine the value of the facilities acquired and any related severance costs.

The MDU option would require a substantial investment in distribution infrastructure to distribute electric power to the customers of the City's MDU. These costs have been identified and estimated by the MEU Study Team at approximately $185 million.[51] The City or its customers would also be subject to the payment of exit fees and other non-bypassable charges mandated by Assembly Bill 1890 and related CPUC orders.[52]

Once established, the MUD would become a full service electric distribution utility and commence serving some 86,652 retail electric customers with an electric load of approximately 147 megawatts.

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51 Annual debt service to support this investment is approximately $20.2 million at an assumed taxable debt interest rate of 6.5%. See Appendix C, Section II.E at 84-87.

52 See discussion in Section IV.F.4.b.(4) below at 125-26.

1. Customer Base

An MDU would encompass all current and future electric customers within the City boundaries. Section II.B at 9-16 describes in detail the customer and load projections used in the analysis, and these are summarized in the following table.

MDU Projected Customers, MWh, And Peak MW By Year

Year	Customers	MWh	Peak MW
2006	86,652	862,186	147
2007	89,412	886,373	151
2008	91,761	908,902	155
2009	94,149	942,025	160
2010	95,737	994,546	170
2011	96,567	1,015,112	174
2012	97,403	1,035,872	177
2013	98,244	1,056,829	181
2014	99,146	1,091,483	188
2015	100,028	1,166,627	201
2016	100,738	1,187,938	205
2017	101,449	1,209,474	209
2018	102,161	1,231,239	213
2019	102,875	1,256,965	217
2020	103,589	1,293,124	224
2021	103,881	1,310,182	227
2022	104,174	1,327,483	230
2023	104,469	1,345,032	233

2. Functional Elements

a. Infrastructure Requirements

(1) Distribution Infrastructure

The MDU option would require substantial investment in distribution infrastructure to distribute power to customers of a City MDU. Such infrastructure would include:

- Distribution Substations
- Primary Distribution Transformers
- Primary Distribution Wires and Poles
- Final Line Transformers

- Secondary Distribution Feeders
- Meters

Under the MDU planning scenario, the City would acquire the SDG&E distribution plant and equipment located within the City's jurisdiction by negotiated purchase or by exercising its power of eminent domain and condemning the property. A comprehensive engineering analysis of distribution equipment inventories, system configuration and condition is required in the valuation phase, prior to the system's negotiated purchase or condemnation. In this phase of evaluation, the MEU Study Team applied average per customer distribution investment benchmarks, as well as SDG&E's reported depreciated book values, to estimate the value of SDG&E facilities within the City. These estimates are set forth in the Appendix C, Section II.E.2 at 84-87.

The SDG&E distribution system value is estimated at $170 million. System start-up costs (service vehicles, inventory, customer service call center and billing equipment) are estimated at $15 million, making the total acquisition costs of implementing the MDU option approximately $185 million.

(2) Supply Portfolio Operations Infrastructure

To procure wholesale energy, the systems identified below must be employed. The City may elect to procure these systems or in the alternative, obtain these services under a full-requirements supply contract. Under a full-requirements supply contract, the required systems and support services would be provided and the associated costs would be bundled into a power contract and embedded in the commodity cost. However, systems and support service costs must be known to quantify the embedded commodity premium in order to allow the City to make informed procurement decisions.

System Requirements

System	Initial Cost	Maintenance	Annual Cost	Potential Outsourcing
Scheduling/Settlements Software	$650,000	40%	$476,667	Scheduling Coordinator
Risk Management Software	$150,000	40%	$110,000	Power Marketer
EDI/IOU Transactions	$100,000	40%	$73,333	Consultant
Scheduling Server	$50,000	10%	$21,667	Scheduling Coordinator
Total Systems Costs			$681,667	

b. Resource Management

(1) Energy Supply - Generation

The MEU Study Team has modeled generation options for the City using operating and cost parameters of a new combined cycle gas turbine operating as a base load plant. These parameters include the unit's heat rate, capacity cost, variable O&M costs, availability factor, hours of planned operation, and the year the resource becomes operational.[53] Sales of any excess production beyond what is needed to serve the City's load could be sold into the market. The price for excess sales reflects a 25% discount relative to the prevailing peak or off-peak price to reflect the probability that excess sales will occur during the lowest priced hours of the on or off peak periods.

The following assumptions were used in the calculation of generation costs:

Capacity:	130 MW
Technology:	Combined Cycle Natural Gas Turbine
Year Online:	2006
Heat Rate:	7,000 BTU/KWh
Capacity Factor:	90%
Variable O&M:	$2 Per MWh
Excess Sales:	75% of Market Price

The MDU operation would benefit by ownership of generation within the City as compared to securing power through power purchase contracts for several reasons. First, the production costs of a new combined cycle gas turbine are expected to be below market-clearing prices. In essence, the MDU would able to capture generation profits within the MDU operation. In addition, generation located within the City boundaries would enable the City to avoid paying transmission congestion charges, which are assessed by the CAISO for use of the transmission grid when congestion is present. Electricity obtained under power purchase contracts may or may not be subject to charges for transmission congestion, depending on whether the point of

[53] See discussion in Section II.C.2 at 21-22.

delivery specified in the contract would require the use of the CAISO-controlled transmission grid.

Internal generation minimizes wholesale transmission charges and other charges assessed by the CAISO. So long as the internal generator operates at a capacity factor greater than 50%,[54] FERC rules require transmission access charges to be assessed on a net load basis, i.e., the internal generation is subtracted from the gross load requirements of the MDU before applying the transmission rates. In addition, internal generation reduces the exposure to charges for reliability services and certain elements of the CAISO's grid management charge. The benefits of internal generation to the MDU's cost-of-service from reduced transmission and CAISO charges are estimated to be approximately $6 million per year.[55]

These wholesale transmission related benefits would not be realized if the City were to supply its load through power purchase contracts or ownership of remote generation that must utilize the CAISO transmission grid for delivery to the City's MDU.

(2) Energy Supply - Power Contracts

The Contracts supply portfolio evaluated for MDU includes the following fixed priced contracts:

Power Purchase Contracts - MDU Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	50	49	5 Years
2006	Peak (6 x 16)	75	59	5 Years
2011	Base (7 x 24)	50	51	5 Years
2011	Peak (6 x 16)	75	61	5 Years
2016	Base (7 x 24)	75	51	5 Years
2016	Peak (6 x 16)	100	61	5 Years
2021	Base (7 x 24)	75	55	3 Years
2021	Peak (6 x 16)	125	66	3 Years

54 Capacity factor is a measure of utilization for a power plant. A plant with a maximum generating capacity of 130 MW would have to produce at least 47,450 MWh in a month (130 MW x 730 hours x 50%) in order to obtain a capacity factor of at least 50%.

55 The CAISO transmission and other charges are discussed and quantified in Appendix C, Section II.D at 83-84.

The following renewable energy contracts were used in modeling the MDU portfolios for both the Generation and Contracts Supply Strategies:

Renewable Energy Contracts - MDU Option

Year	Product	Quantity (MW)	Price ($/MWh)	Term
2006	Base (7 x 24)	7	52	1 Year
2007	Base (7 x 24)	8	51	1 Year
2008	Base (7 x 24)	10	52	1 Year
2009	Base (7 x 24)	11	52	1 Year
2010	Base (7 x 24)	13	52	1 Year
2011	Base (7 x 24)	15	53	1 Year
2012	Base (7 x 24)	17	54	1 Year
2013	Base (7 x 24)	18	54	1 Year
2014	Base (7 x 24)	20	54	1 Year
2015	Base (7 x 24)	23	54	1 Year
2016	Base (7 x 24)	25	53	1 Year
2017	Base (7 x 24)	28	53	1 Year
2018	Base (7 x 24)	29	55	3 Years
2021	Base (7 x 24)	30	58	3 Years

See Appendix C, Section II.B.2 at 68-77.

c. Operations and Maintenance

(1) Distribution Operations and Maintenance Costs

The MEU Study Team used the results of a nationwide benchmarking study of municipal electric utilities to estimate distribution O&M costs for the City. The study groups municipal electric utilities by size into five strata and reports average per customer O&M costs within each strata for distribution O&M, customer service expenses, and administrative and general expenses. The average total annual distribution O&M costs reported by participants in the study range from $246 to $594 per customer, reflecting a wide range of urban and rural municipal utilities of various sizes and population densities.

The MEU Study Team has also used a targeted set of case studies of California municipal electric utilities to obtain O&M estimates that would be more reflective of the costs expected for the City municipal electric utility. Data are available for years 1998-2001, and the average total annual distribution O&M costs range from $231 to $380 per customer. For this analysis, the four-year average per customer O&M costs of California municipal utilities of similar size as Chula Vista was used to predict the cost for distribution operations. Four municipal utilities with between 50,000 and 90,000 customers were selected. These were Burbank, Glendale, Pasadena, and the Turlock Irrigation District.

Based on this analysis, the average annual O&M cost estimated for the City is $270 per customer. By comparison, the MEU Study Team has calculated the average distribution O&M costs for the entire SDG&E system to be $198 per customer, using the following SDG&E FERC Form 1 data:

Category	Amount
Distribution O&M	$76,310,456
Customer Service O&M	$78,025,205
Allocation of A&G	$94,739,319
Total Distribution O&M	$249,074,980
Total Customers	1,255,268
Distribution O&M Per Customer	$198

The lower figure for SDG&E reflects the economies of scale in distribution operations that are not available to smaller distribution systems. The capital financing and tax advantages of municipal electric utilities are offset to a degree by higher per capita O&M costs typical of smaller utilities.

(2) Electric Portfolio Operations

O&M activities related to electric portfolio operations include those necessary to procure electricity in the wholesale markets, schedule electricity transactions with the CAISO, conduct financial settlements for wholesale electricity purchases and sales, and interface with SDG&E who would be providing billing, metering, and customer services to CCA customers.

Portfolio operations costs are the costs associated with various activities related to procuring electricity for retail customers. Portfolio operations activities include load forecasting, procurement of electricity from wholesale electricity sellers, risk management and controls. Activities related to retail pricing (load research, cost of service, rate design) are also included in this cost category for purposes of the pro forma analysis.

Scheduling coordination costs are the costs associated with scheduling and settling electric supply transactions with the CAISO. The analysis assumes that the City would become a CAISO certified Scheduling Coordinator, which would require acquisition of scheduling and settlements software and operation of an around-the-clock scheduling desk.

Total costs of portfolio operations and scheduling coordination are modeled as a combination of fixed and variable costs. Fixed costs, largely associated with the minimum required personnel, are approximately $2,000,000 per year. Variable costs are estimated at $2.50

per MWh to account for increases in the size and sophistication of the portfolio operations and corresponding increases in the overall size of the utility.

d. Human Resources

The MDU human resource requirements were determined through a six-step approach. The first step assessed the number of full-time employees (FTE) per utility customer at fifteen publicly owned California electric utilities.[56] The second step applied the number of employees into the following five functional work groups based upon the percentage of total FTE population in four prototypical utility operations:

1. Executive Management (and support staff)
2. Distribution Engineering & Operations
3. Customer and Energy Services
4. Power Operations
5. Finance

The third step identified the percentage of employees in each position within the given work group; position specific FTE requirements were derived. The fourth step identified those functional positions where the number of employees correlates highly with the number of customers they serve. Such positions include meter readers, call center customer service representatives, line crew technicians and foremen, substation technicians and supervisors. The number of employees required in these positions was adjusted to reflect that correlation based on benchmarked transactional volumes.

The fifth step identified those positions that are not correlated with customer numbers or transaction volumes. Such positions correlate with system and shift requirements such as SCADA system operators, power schedulers and real-time operators where operations often operate across 3-shifts, 24 hours per day. The sixth step applied employee payroll, benefits and overhead expense to employee populations to provide a cross check with pro forma O&M cost assumptions based upon reported national, state and regional electric utility O&M costs.

No employees were allocated to power plant operation and maintenance. The MEU Study Team recommends that, if the City takes an equity position in generation facilities, it rely upon the primary equity holder to operate or subcontract the operation of the facilities.

The chart on the following page lists the MDU human resource requirements by organization and position:

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56 *See* Appendix C, Section IV.B at 134-38, California Public Utility Statistics.

MDU Human Resource Requirements

Director & Support Staff
3

Finance Mgr. & Supt Staff
3

Distribution Engineering & Operations		**Customer & Energy Services**		**Power Operations Group**	
Manager & Support Staff	2	Customer & Energy Services Mgr.	1	Portfolio Operations	
		ESRs	4	Management	3
Substations (Supervisors and Tech.s)	19	Field Services	2	Rates/Forecasting	3
		Meter Readers	14	Resource Planning	2
Dispatch (SCADA)	3			Trading/Risk Management	4
Operators	12	Credit & Collections	1	Wholesale Settlements	2
		Accounting	3	Pre-Schedulers	2
Construction	4	Call Ctr CSRs	8	Real Time Desk	6
Troubleshooters	5	Billing Clerks	5	Credit	1
Materials Techs	2			IOU Transactions/Audits	2
Line Crew and Foremen	32			IT Support	1
Metering					
Electronics Techs	4			Power Production	
				Power Plant Op.s	0
Service Planning (New Services)	1				
Engineering Techs	5				
Drafting Techs	4				
Engineering	1				
Power Engineers	5				
Computer Maintenance	1				
	100		38		26
		Total MDU Staff	170		

3. Costs and Benefits

a. Financial Analyses

A financial analysis was performed to render financial pro forma structured as consolidated statements of income for each MEU structure option. The consolidated statements based on the financial pro forma are located in this report in Appendix C, Section II.I at 97-98. As noted above, savings or potential income is the margin between current retail power costs charged by SDG&E, and each MEU option's cost to provide the power. The MEU Study Team began its evaluation of each utility structure option with a planning horizon beginning in 2004 and projected costs 20-years forward to 2023. Evolving legislation, regulation, implementation lead times and cost considerations caused the MEU Study Team to project MEU implementation beginning in 2006. The resulting study period was subsequently revised from 2006 to 2023, as reflected in financial pro forma for each MEU option.

As a regulated public utility, SDG&E provides utility services at regulated cost-based rates. Hence, SDG&E's rates are directly tied to a demonstrated revenue requirement and its rate structures are required to affect equitable cost allocation among customer classes. The financial analysis provided herein compares SDG&E's revenue requirement with the revenue requirement of each MEU option to determine potential savings or income. Pro forma summary tables compare each MEU option based on its relative ability to produce operational cost savings or benefits.

The financial analysis for the MDU option evaluates the costs and financial benefits for the City to take the following actions: 1) acquire SDG&E's electric distribution system and perform operation and maintenance activities; 2) obtain required electric energy resources through entitlement to power plant production and/or from wholesale power contracts; and 3) provide full electric utility services to the City's residents and businesses.

b. Financial Analysis Structure

SDG&E's current and projected electric rates were applied to the MDU customer population electric loads, evaluated under Section II.B at 9-16 and summarized above at 100, to arrive at SDG&E's revenue requirement or retail customer energy costs. The MDU's operating expenses were projected and subtracted from SDG&E's revenue requirement to arrive at the projected financial benefit. The elements contained in the analysis are summarized below:

- <u>SDG&E Forecast Generation Rates</u>[57]
  - Utility Retained Generation
  - Qualifying Facility Generation
  - Bilateral Power Purchase Contracts
  - CAISO charges
  - Residual Spot Market Purchases or Sales

- <u>MDU Energy Cost</u> (Commodity Costs)[58]
  - Spot Market Purchases
  - Power Purchase Contracts
  - Renewable Energy Contracts
  - Generation Ownership

[57] *See* Appendix C, Section II.A at 64-67.

[58] *See* Appendix C, Section II.B.2 at 68-77.

- <u>California Independent System Operator Charges charges (CAISO)</u>[59]
  Ancillary Service
  Grid Management
  Reliability Services
  Congestion Costs
  Grid Operations
  Unaccounted for Energy
  Neutrality Adjustments
  Deviation Charges

- <u>Transmission and Scheduling Costs</u>[60]
  Scheduling and Settlements System
  Procurement and Maintenance Costs
  Labor

- <u>Non-Bypassable Charges</u>[61]
  -CPUC Exit Fees
    - Uneconomic Utility Retained Generation and Power Contracts
    - DWR Power Purchase Contracts
    - DWR Bond Charges - Financing Past Purchases

  -Other Non-Bypassable Charges (applies to Greenfield portion only)
    - Public Purpose Program Charges[62]
    - Nuclear Decommissioning Charges
    - Fixed Transition Amount Charges

- <u>Distribution System Capital Cost</u>[63]
  Costs Associated with Acquiring the Distribution System Assets

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59 *See* Appendix C, Section II.D at 83-84.

60 *See* Appendix C, Section II.B.3 at 77-78.

61 *See* Appendix C, Section II.C at 78-87.

62 Public Purpose Program Charges are included herein to support an evaluation of savings based on a comparison of baseline SDG&E customer bill charges and the charges customers would pay under this City MEU business model. However, revenue collected by the City associated with this charge would be available to the City to allocate to various activities that are identified in Appendix C, Section II.C.2 at 81-82.

63 *See* Appendix C, Section II.E at 84-87.

- Distribution System Operations and Maintenance Costs[64]

- In-Lieu Payments to Replace Lost Revenues[65]
  Lost or Reduced Franchise Fee Payments
  Lost or Reduced Property Tax Payments

The MDU option cost benefits were assessed based upon two energy supply strategies. In the first supply strategy it is assumed the City's MDU will take an ownership position in a power generation facility (Generation Supply Strategy). In the second, it is assumed the City's MDU will purchase all of its energy requirements in the wholesale energy market by executing power contracts with suppliers (Contracts Supply Strategy).

Power costs were allocated to resource supply options for the given supply strategy as follows:

2006 Energy Resource Costs ($) by Supply Strategy

	Generation		**Contracts**	
Market Purchases	$4,317,306	9.8%	$2,802,774	5.6%
Contracts	$3,188,640	7.2%	$47,094,240	94.4%
Power Production	$36,644,395	83.0%		
	$44,150,341		$49,897,014	

Generation Strategy - Major Capital Expenditures:

Implementing a CCA or MDU with the Generation Supply Strategy option requires constructing new generation or acquiring an interest in a generation project. To support the Generation Supply Strategy would require initial capital expenditures estimated at $78 million. This figure is derived based on an assumed ownership of 130 MW at an installed capital cost of $600,000 per MW. Annual debt service to support this investment would be approximately $5.4 million at an assumed tax-exempt debt interest rate of 5.5%. This cost, as well as generation facility operations and maintenance and fuel cost, is included in the Pro Forma Table below at 112 under Commodity Costs and in Appendix C, Section II.I at 97, Section V. Operating Expenses, (A)(iii) Power Production.

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64 *See* Appendix C, Section II.F at 87-88.

65 *See* Appendix C, Section II.H at 88-89.

c. Pro Forma Results

MDU option financial pro forma were prepared for both the Generation and Contracts Supply Strategies. *See* Appendix C at 97-98.

(1) MDU - Generation Supply Strategy

Total estimated costs of MDU operations are summarized in the table below for the Generation Supply Strategy and compared to projected SDG&E electric commodity related charges. The costs of MDU operations are broken out among the major cost of service elements. The most significant of these is the electric commodity costs, which is primarily the capital and operating costs of the MDU's generator, plus purchases under renewable energy contracts and spot market purchases. The next largest cost category is distribution operations, which includes operations and maintenance, customer service and information (billing), and administrative and general expenses. Other significant costs include the financing charges for the MDU's distribution capital investments and non-bypassable charges/exit fees. Less significant costs include ancillary services and CAISO charges, portfolio operations, and scheduling coordination charges, foregone franchise fee payments, and in lieu payments for county property taxes.

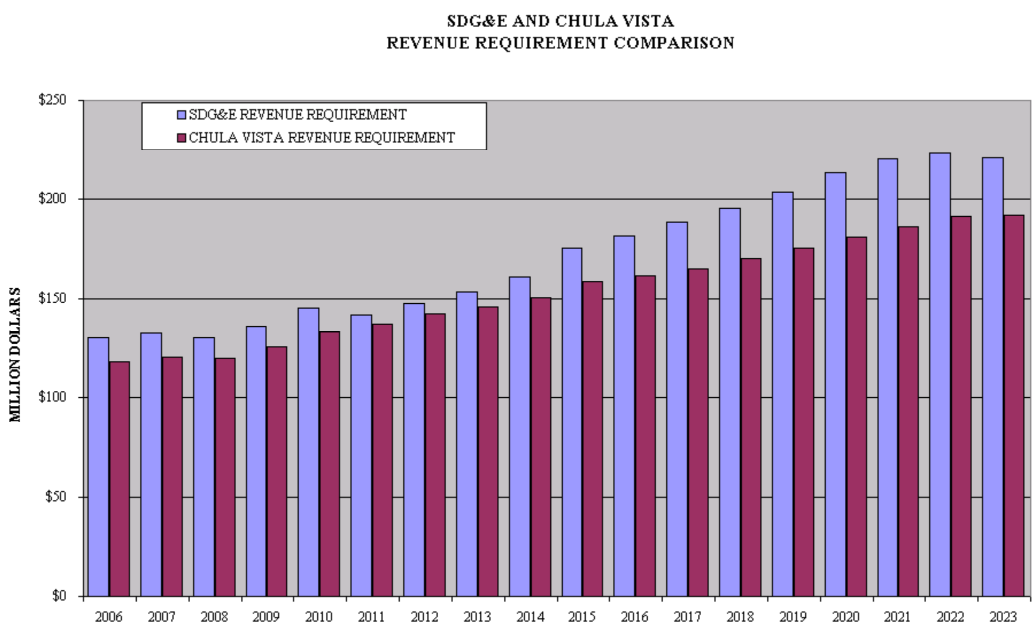
Savings are the difference between the MDU costs and the charges that SDG&E would collect through rates under SDG&E's current and projected retail electric rates. As shown on the Chart below, significant savings are projected to occur in every year of the study period.

Pro Forma Summary and Projected Savings - MDU Generation Supply Strategy (Millions of Dollars Per Year)

Year	Commodity Costs	Ancillary Services/ISO Costs	Transmission & Scheduling	Non-bypassable Charges	Distribution Capital	Distribution Ops.	Franchise Fees/Taxes	Total Costs	SDG&E Charges	Savings
2006	44.2	2.7	4.9	20.1	18.9	24.6	2.8	118.1	130.4	12.3
2007	44.3	2.9	5.1	19.7	19.7	26.0	2.8	120.5	132.5	12.0
2008	46.6	3.2	5.3	14.0	20.3	27.4	2.9	119.6	130.1	10.5
2009	48.7	3.5	5.6	15.2	21.0	28.8	2.9	125.5	136.2	10.7
2010	51.6	3.9	6.0	16.8	21.6	30.1	2.9	132.9	145.1	12.2
2011	53.5	4.2	6.2	17.6	21.8	31.1	2.9	137.3	142.0	4.7
2012	55.5	4.5	6.4	18.8	22.0	32.1	3.0	142.4	147.4	5.1
2013	56.5	4.7	6.6	19.3	22.3	33.2	3.0	145.6	153.3	7.8
2014	58.7	5.1	6.9	19.7	22.5	34.3	3.0	150.3	161.2	10.8
2015	63.0	5.8	7.6	21.0	22.7	35.5	3.0	158.7	175.4	16.6
2016	63.4	6.1	7.8	21.4	22.9	36.6	3.1	161.4	182.0	20.6
2017	64.4	6.4	8.1	21.8	23.1	37.8	3.1	164.7	188.8	24.1
2018	67.4	6.8	8.3	22.3	23.3	39.0	3.1	170.4	195.9	25.5
2019	69.8	7.2	8.6	22.8	23.5	40.3	3.2	175.3	203.8	28.5
2020	72.4	7.7	8.9	23.5	23.7	41.6	3.2	181.0	213.6	32.6
2021	75.6	8.1	9.1	23.9	23.8	42.7	3.2	186.5	220.6	34.1
2022	78.5	8.5	9.3	24.3	23.9	43.9	3.3	191.7	223.5	31.9
2023	78.9	8.8	9.5	18.9	25.5	47.4	3.3	192.1	220.8	28.7

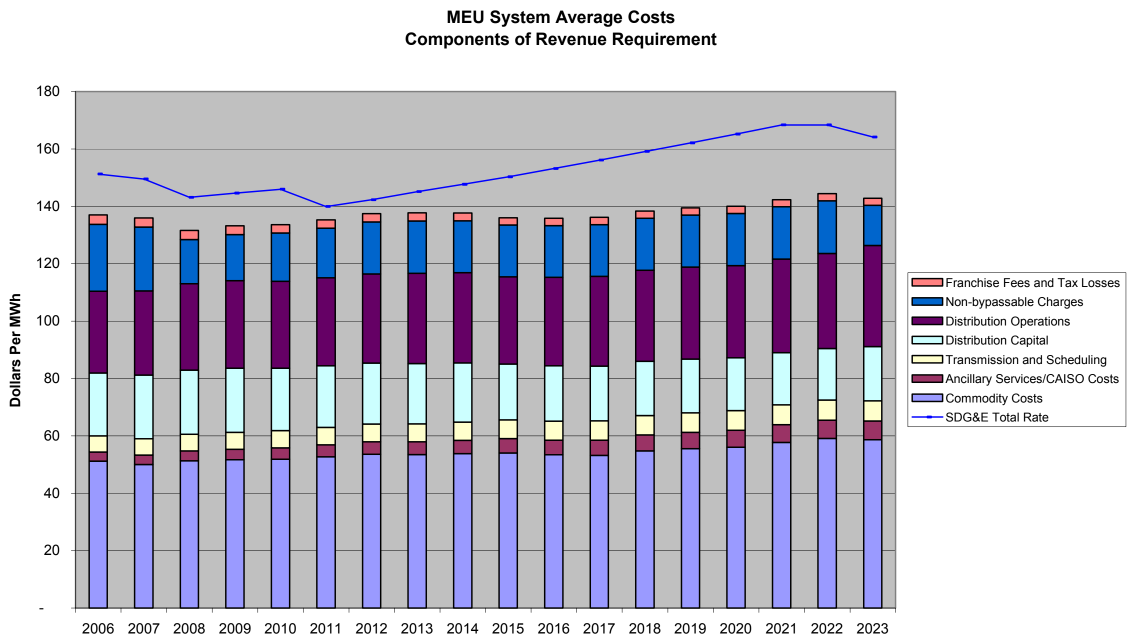
The following Chart 7 compares the total MDU cost of service to the generation-related charges projected for SDG&E.

Chart 7: Comparison Of MDU Costs Based On Supply Generation Strategy



The components of the MDU costs on a dollar per MWh basis are shown in Chart 8 below for the Generation Supply Strategy and compared to SDG&E electric commodity charges.

Chart 8: MDU Cost Components On A Per MWh Basis



(2) MDU - Contracts Supply Strategy

Total estimated costs of MDU operations are summarized in the table below for the Contracts Supply Strategy and compared to projected SDG&E electric commodity related charges. The costs of MDU operations are broken out among the major cost of service elements. The most significant of these is the electric commodity costs. The commodity costs primarily reflect the long-term power purchase contracts that form the core of the supply portfolio, as well as the renewable energy contracts and spot market purchases.

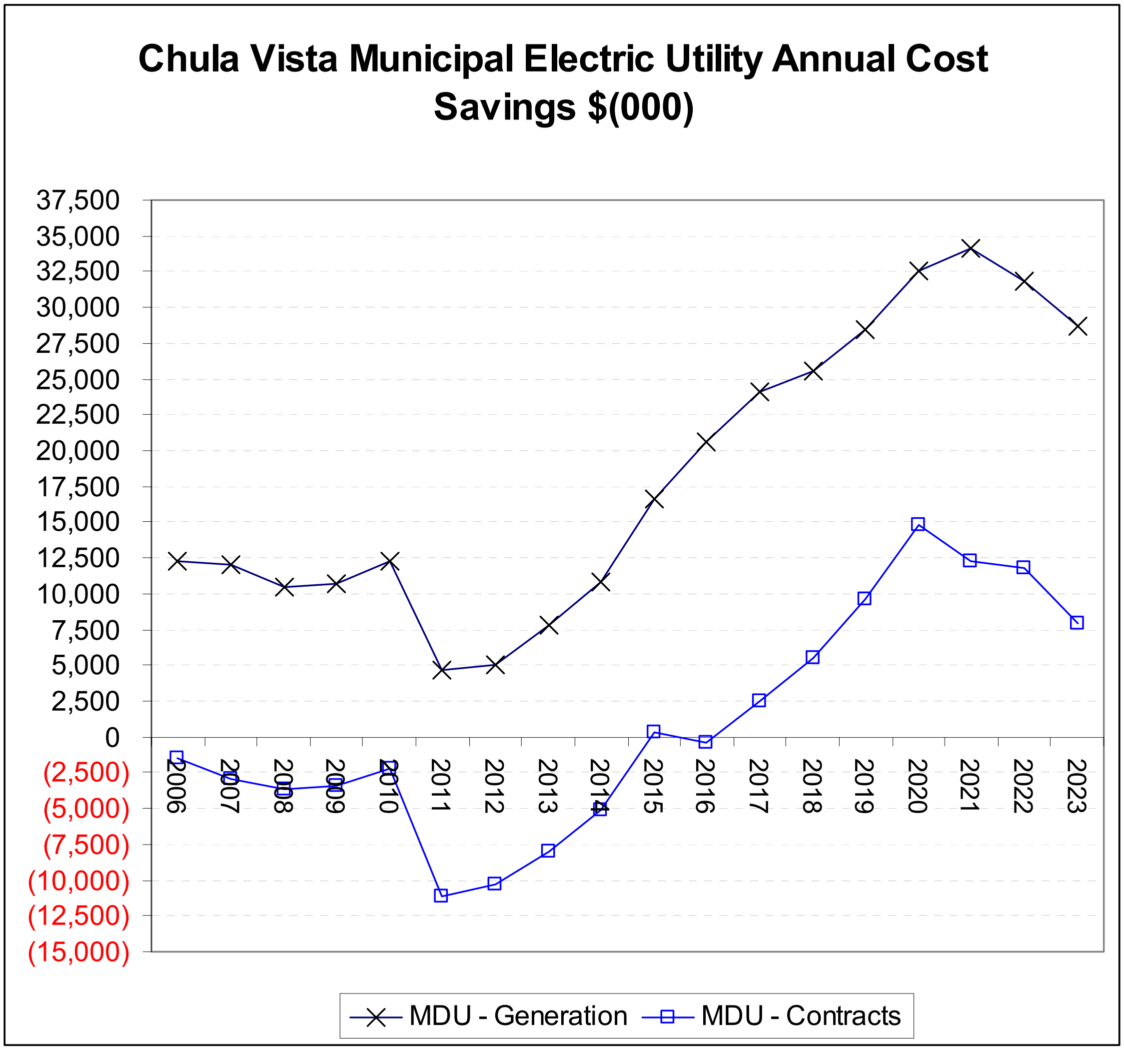
The next largest cost category is distribution operations, which includes operations and maintenance, customer service and information (billing), and administrative and general expenses. Other significant costs include the financing charges for the MDU's distribution capital investments and nonbypassable charges/exit fees. Less significant costs include ancillary services and CAISO charges, portfolio operations and scheduling coordination charges, foregone franchise fee payments and in lieu payments for county property taxes.

Savings are the difference between the MDU costs and the charges that SDG&E would collect through rates under SDG&E's current and projected electric rates. As shown on the Chart below, savings are not projected to occur until at least 2015. Based on the pro forma results, the MEU Study Team has concluded that an MDU that relies exclusively on market purchases of wholesale electricity to serve the load requirements of its customers would not be a cost-effective option for the City in the near term.

Pro Forma Summary and Projected Savings - MDU Contracts Supply Strategy (Millions of Dollars Per Year)

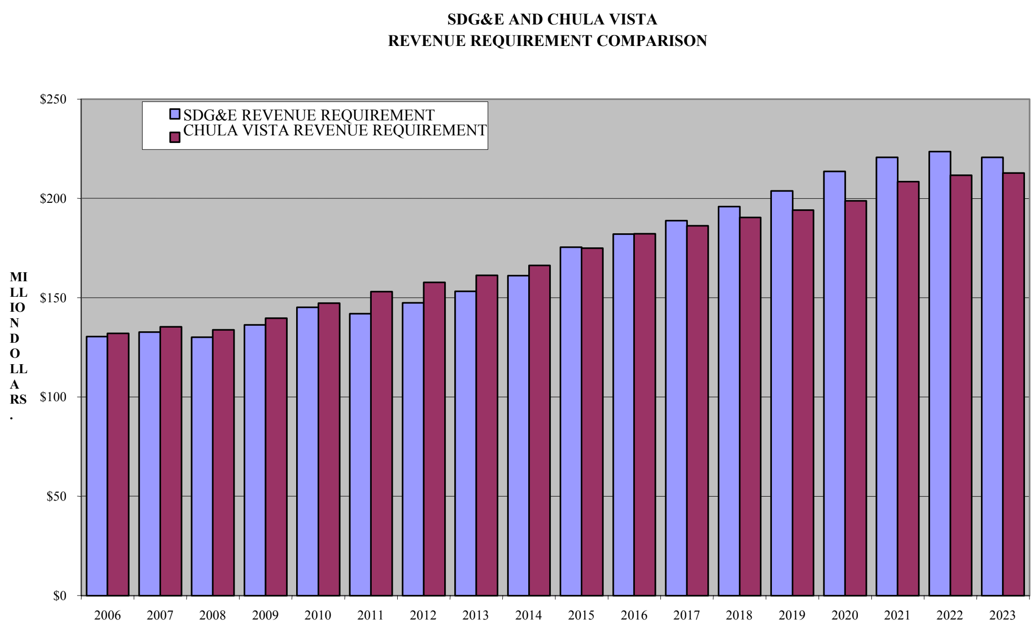
Year	Commodity Costs	Ancillary Services/ISO Costs	Transmission & Scheduling	Non-bypassable Charges	Distribution Capital	Distribution O&M	Franchise Fees/Taxes	Total Costs	SDG&E Charges	Savings
2006	49.6	6.3	9.3	20.5	18.9	24.6	2.8	131.9	130.4	(1.5)
2007	50.8	6.5	9.5	20.1	19.7	26.0	2.8	135.4	132.5	(2.9)
2008	52.2	6.8	9.8	14.4	20.3	27.4	2.9	133.8	130.1	(3.7)
2009	54.1	7.2	10.1	15.5	21.0	28.8	2.9	139.7	136.2	(3.4)
2010	57.1	7.8	10.7	17.2	21.6	30.1	2.9	147.3	145.1	(2.2)
2011	60.2	8.1	10.9	18.0	21.8	31.1	2.9	153.1	142.0	(11.1)
2012	61.7	8.5	11.2	19.2	22.0	32.1	3.0	157.8	147.4	(10.4)
2013	62.9	8.9	11.5	19.7	22.3	33.2	3.0	161.4	153.3	(8.1)
2014	65.0	9.3	11.9	20.2	22.5	34.3	3.0	166.2	161.2	(5.1)
2015	69.4	10.2	12.7	21.5	22.7	35.5	3.0	175.0	175.4	0.3
2016	72.5	11.2	13.7	22.3	22.9	36.6	3.1	182.3	182.0	(0.4)
2017	73.9	11.6	14.0	22.7	23.1	37.8	3.1	186.3	188.8	2.5
2018	75.4	12.1	14.3	23.1	23.3	39.0	3.1	190.4	195.9	5.5
2019	76.6	12.5	14.5	23.5	23.5	40.3	3.2	194.1	203.8	9.7
2020	78.3	13.0	14.8	24.1	23.7	41.6	3.2	198.8	213.6	14.8
2021	85.3	13.6	15.0	24.7	23.8	42.7	3.2	208.4	220.6	12.3
2022	86.2	14.1	15.3	25.1	23.9	43.9	3.3	211.7	223.5	11.8
2023	87.1	14.5	15.5	19.6	25.5	47.4	3.3	212.8	220.8	8.0

The following chart demonstrates that adoption of a Generation Supply Strategy would result in substantially greater benefits that the Contracts Supply Strategy if the City implements an MDU option:



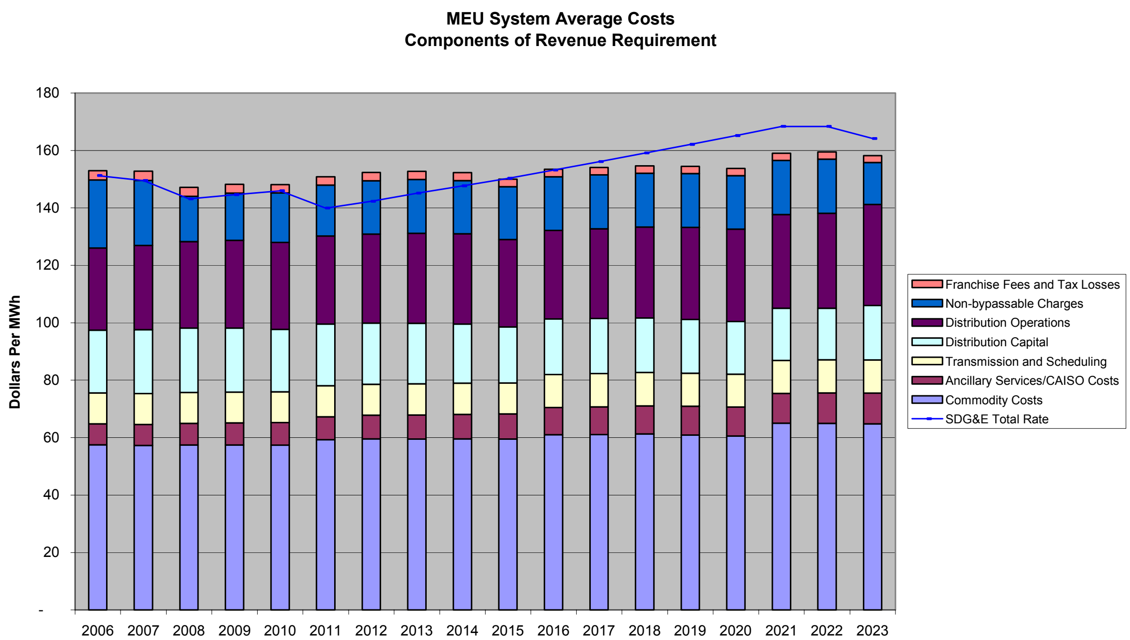
The following Chart 9 compares the total MDU cost of service to the generation-related charges projected for SDG&E.

Chart 9: Comparison Of MDU Costs Based On Contracts Supply Strategy



The components of the MDU costs on a dollar per MWh basis are shown in the Chart 10 below for the Contracts Supply Strategy and compared to SDG&E electric commodity related charges.

Chart 10: MDU Cost Components On A Per MWh Basis



Pro forma detail for the MDU option, with both Generation and Contracts Supply Strategies, is located in the Appendix C, Section II.I at 97-98.

d. Intangibles

(1) Benefits

If Chula Vista decides to pursue this option, its residents could realize a number of benefits, including the likelihood of lower-priced power, more stable electricity rates, local control over the rates, rate design and the use of funds dedicated to public benefit and progress, improved reliability, and opportunities for economic development.

In recent years, most of California's electric consumers have seen their electric rates skyrocket – with a notable exception: the customers of most of California's municipal utilities. While some municipal utility customers also saw rate increases, the increases were not on the order of magnitude that the customers of the California IOUs have experienced. The major reason municipal utility rates did not increase as dramatically as IOU rates is that municipal utilities were not fully and forcefully committed to the failed California deregulation experiment, and therefore not substantially reliant on the energy spot markets in 2000 and 2001. Most municipal utilities had either developed their own generation resources, or entered into long-term power contracts that "locked-in" and stabilized future energy costs, and were therefore not dependent upon spot-market purchases.

Municipal utilities have an inherent price advantage over IOUs because the municipal utility is not motivated to produce profits for shareholders. Municipal utilities are permitted to set rates which cover both capital and operating expenses and also fund utility reserve accounts, fund in-lieu-of-tax payments to local governments, and fund other worthy public works projects. In addition, the municipal utility has access to tax-exempt financing for many capital expenditures. These key components provide the City with a significant advantages regarding retail electricity rates as compared to remaining a full requirements customer of SDG&E.

Another major advantage with this option would be local authority and control. For instance, the future potential City of Chula Vista Electric Utility Department could make resource decisions, develop maintenance practices, develop capital improvement programs, and make other decisions relating to the operation of the utility for the sole benefit of City residents and businesses. For instance, the City could elect to purchase electricity from more environmentally benign resources in comparison to SDG&E's resource mix. The City Council would be the only entity to set electric rates. Such rates would be designed to meet any unique circumstances existing within the City's service territory. Currently, these decisions are being made by SDG&E (for the benefit of its shareholders) under the regulation of the CPUC and the FERC. Municipal utilities are not, for the most part, subject to CPUC or FERC regulation.[66] Rather, they are, for the most part, subject to self-regulation and control by the City Council or a municipal utility board or commission. An important facet of local control which should not be overlooked is the ability of the Chula Vista City Council to fashion programs to utilize public goods charges (discussed in below and in Section III.C.1.a of Appendix B at 16-17). Such programs must meet the requirements of state law, but can be designed to meet the unique requirements of Chula Vista customers and provide direct benefits to Chula Vista residents and businesses.

Public Utilities Code 385 authorizes and requires local publicly owned electric utilities to collect, through rates for local distribution service, revenue allocated to public benefits programs. The public benefits charges are to be not less that the lowest expenditure level of the three largest IOUs on a percent of revenue basis for year ending December 21, 1994. Public benefits related charges are currently a minimum of 2.85 percent of the publicly owned electric utility's revenue requirement.

Public benefit programs referred to include the following:

i. Cost-effective demand-side management services to promote energy efficiency and energy conservation;

66 *See* discussion in Appendix B Section I.C at 15-27.

ii. New investment in renewable energy resources and technologies (subject to applicable statutes);
iii. Research, development and demonstration programs for public interest to advance science and technology that is not adequately provided by competitive and regulated markets; and
iv. Service for low-income electricity customers, including, but not limited to, energy efficiency services, education, weatherization, and rate discounts.

Revenue associated with this charge would be available to the City to allocate to various activities identified above.

Finally, the City could provide economic incentives for specific economic development areas within the City, and design rates to match those incentives.

As shown on the following chart, if Chula Vista forms an MDU and commences the operation of a full electric distribution utility, it would be the 11th largest utility in California, based on customer count and 20th based on energy sales.

California Electric Utilities *(Source: California Energy Commission 2001 Statistics)*

	Accounts	MWh	% Energy	Customer Ranking
Pacific Gas and Electric Company	4,756,159	79,441,589	34.08%	1
Southern California Edison Company	4,448,024	78,453,624	33.66%	2
Los Angeles Department of Water and Powe	1,405,524	22,375,712	9.60%	3
San Diego Gas and Electric Company	1,242,735	15,212,291	6.53%	4
Sacramento Municipal Utility District	475,410	9,333,938	4.00%	5
City of Anaheim	109,548	2,511,542	1.08%	6
Imperial Irrigation District	102,901	2,711,321	1.16%	7
Modesto Irrigation District	99,550	2,244,939	0.96%	8
City of Riverside	96,102	1,720,653	0.74%	9
City of Glendale	83,489	1,114,569	0.48%	10
City of Chula Vista	78,317	862,186		11
Turlock Irrigation District	76,565	1,445,313	0.62%	12
City of Pasadena	59,354	1,104,676	0.47%	13
City of Burbank	51,406	1,050,244	0.45%	14
Silicon Valley Power	48,083	2,517,729	1.08%	15
Pacificorp	44,565	816,107	0.35%	16
Sierra Pacific Power Company	43,873	505,223	0.22%	17
City of Redding	39,653	671,507	0.29%	18
City of Roseville	39,070	947,855	0.41%	19
City of Alameda	33,140	364,491	0.16%	20
City of Palo Alto	28,200	1,100,596	0.47%	21
City of Lodi	24,618	413,600	0.18%	22
Southern California Water Company	21,603	126,596	0.05%	23
City of Colton	17,679	299,034	0.13%	24
City of Lompoc	14,913	129,614	0.06%	25
City of Azusa	14,773	226,897	0.10%	26
Lassen Municipal Utility District	12,068	120,182	0.05%	27
Truckee-Donner Public Utility District	11,257	122,451	0.05%	28
City of Banning	10,141	129,300	0.06%	29
City of Ukiah	7,360	94,108	0.04%	30
Trinity Public Utility District	6,558	75,471	0.03%	31
Plumas-Sierra Rural Electric Cooperation	6,250	121,820	0.05%	32
City of Healdsburg	5,342	66,936	0.03%	33
City of Needles	4,100	79,344	0.03%	34
Shasta Dam Area Public Utility District	4,082	67,239	0.03%	35
Surprise Valley Electrical Corporation	4,044	101,517	0.04%	36
Anza Electric Cooperative, Inc.	3,567	36,109	0.02%	37
City of Gridley	2,280	28,180	0.01%	38
City of Vernon	2,067	1,128,048	0.48%	39
Merced Irrigation District	881	271,153	0.12%	40
City of Biggs	662	10,706	0.00%	41
Calaveras Public Power Agency	240	26,494	0.01%	42
Central Valley Project	86	2,743,160	1.18%	43
Tuolumne County Public Power Agency	85	25,133	0.01%	44
Valley Electric Association, Inc.	26	6,905	0.00%	45
City of San Francisco	14	897,947	0.39%	46
Boulder City/Parker Davis	n/a	88,130	0.04%	47
City of Escondido	n/a	400	0.00%	48
Total	13,458,047	233,080,393		

A City Municipal Distribution Utility Would Be The 11th Largest Utility Out Of The State's 48 by Customer Count – 20th By Energy Sales

(2) Risks

One obvious and large risk inherent in this option is the amount of resistance that SDG&E would exert against the City moving forward with a public power entity. Ideally, if the City decided that it wanted to proceed with the implementation of a City MDU, the City would be able to reach a negotiated settlement with SDG&E for the acquisition of its distribution assets. However, it is more likely that SDG&E would resist the acquisition of its distribution facilities, requiring the City to resort to the use of the power of eminent domain.

In considering the MDU option, the City should not underestimate the potential strong opposition SDG&E will wage against the taking of its distribution assets or infringement on its customer base. The City should anticipate that SDG&E will use every legal and political tool available to frustrate, defeat or delay the implementation of the City's MDU option. The Eminent Domain Law [67] gives the property owner several opportunities to defeat the acquisition, beginning with the contest of the Resolution of Necessity. SDG&E can also delay the implementation process by contesting the terms and conditions of the interconnection before the FERC.[68] At the bottom line, SDG&E's political and legal resistance to selling its distribution assets will substantially increase the start-up costs associated with the creation of a new utility.

It is worth noting that SDG&E recently funded a citizen's initiative in San Marcos in opposition to the City Council's efforts to implement a Greenfield project to serve newly developed areas within the City.[69]

Another impediment may involve issues surrounding separation or "islanding" from other parts of the SDG&E system. There would likely be certain physical distribution asset separation problems as portions of SDG&E's distribution lines cross other jurisdictional boundaries. This may require the construction of additional distribution substations, installation of net metering technologies, or other local distribution design reconfigurations resulting in the award of severance costs to SDG&E as part of the condemnation process,[70] resulting in increased costs of financing the distribution assets.

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67 *See* discussion in Appendix B, Section II.A at 28-30.

68 *See* discussion in Appendix B, Section II.C.3 at 33-35.

69 The San Diego Union Tribune, August 1, 2003. According to San Marcos Councilman Lee Thibadeau: "SDG&E is doing everything it can to interfere with the city's right to establish our own utility and save our residents millions of dollars."

70 *See* Appendix B, Section II.C.2 at 32-33.

To provide a cost benefit over the current SDG&E service, the City would need to be able to acquire the distribution system, provide or obtain energy and related services, perform operation and maintenance services, billing, settlements, and collections, and perform long-term planning, all at a cost of less than the current provider. Based upon the financial pro forma performed by the MEU Study Team, the City can meet this challenge through the formation and operation of a full service MDU.

4. Legal/Regulatory

Cal. Const. Art. XI, §9 provides specific authority for municipal corporations to provide utility services both within and without of their boundaries ". . . except within another municipal corporation which furnishes the same service and does not consent." Cal. Pub. Util. Code § 10002 provides that a municipal corporation may acquire, construct, own, operate, or lease any public utility. A Public Utility, in this context, is defined as the supply of a municipal corporation alone or together with its inhabitants, or any portion thereof, with water, light, heat, power, sewage collection, treatment, or disposal for sanitary or drainage purposes, transportation of persons or property, means of communication, or means of promoting the public convenience. *See* Cal. Pub. Util. Code § 10001.

Publicly owned municipal utilities (the various forms of which are set forth and described at Cal. Pub. Util. Code § 9604(d)) are not regulated by the Public Utilities Commission or any other supervising agency, in the absence of a legislative grant of authority (Cal. Const., art XII, § 3; *see also*, *County of Inyo v. Public Utilities Commission* (1980) 26 Cal. 3d 154).

No formation or implementation process is specified by state law for the creation of such a utility.

As discussed in Section I above, the City of Chula Vista has already taken the initial steps in the formation of an MEU with the adoption, on June 5, 2001, of Ordinance No. 2835 establishing the City as a municipal utility.

a. Exercise of the Power of Eminent Domain

Until Chula Vista elects to acquire or operate an electric distribution system or other utility facilities to serve the full or partial electric and gas requirements of customers within the City, it is premature to discuss, in any detail, the procedures and requirements applicable to the exercise of the powers of eminent domain in the State of California. Such detailed discussion is better left for development and analysis in the implementation phase if Chula Vista elects to pursue this option. At the same time, it is important for Chula Vista to understand that it can exercise the option of acquiring utility facilities, including SDG&E's electric distribution system, and to have some understanding of both the procedures involved in exercising this option and the public interest standard that must be met if the condemnation is challenged by SDG&E.

In this regard, in California, a public entity, such as Chula Vista, does have the right to acquire property for public use, including public utility facilities and franchises, using the process of eminent domain.[71] The procedure which a municipality or other entity (e.g. Municipal Utility District) must follow in acquiring public utility facilities or franchises may be summarized briefly as follows:

Offer: The public entity or municipality must make an offer to the property owners. This offer must reflect what the public entity or municipality believes is just compensation for the property.
Notice and Hearing: Prior to issuing a resolution of necessity, the public entity or municipality must provide, to the property owners, notice and opportunity to be heard with regard to public interest, public good, and the necessity of the property's acquisition.
Recommendation: After holding the necessary hearing, the governing body of the public entity (normally the legislative body of the public entity) must issue a written summary of the hearing and a written recommendation as to whether to adopt the resolution of necessity.
Resolution of Necessity: The governing body may then issue a resolution of necessity
Final Offer: At least 30 days prior to trial, the public entity must file its final offer and the owner must file its final demand.
Commencement of Eminent Domain Proceeding: After issuance of a resolution of necessity, the public entity must file a complaint with the superior court.

A detailed analysis of the California Eminent Domain Law [72] and legislation related to the acquisition of facilities and property for the purpose of providing utility services is set forth in Appendix B, Section II.A at 28-32. This analysis includes a discussion of the various methods of valuation which may be used in establishing the "just compensation" which must be paid to SDG&E for the taking of its electric distribution assets.

b. Cost Exposure

In the event that Chula Vista elects to form and operate an MDU through the acquisition or condemnation of SDG&E's electric distribution system, it will be exposed to several classes or types of costs, which must be taken into consideration in determining whether or when to proceed with this undertaking. The legal basis for each class of potential costs are set forth and discussed in Appendix B, Section II.C at 32-41. Those costs, which are presently

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71 *See* Cal. Civ. Proc. Code §§ 1240.010 and 1240.110.

72 See Cal. Civ. Proc. Code §§ 1240.010, *et. seq.*

known or can be estimated, are quantified in Appendix C, Section II.C.1 at 78-81 and Section E.2 at 84-89. The principal cost factors involved in this feasibility analysis are:

(1) Acquisition Costs

The acquisition costs are those associated with the acquisition, by negotiation or by condemnation, of SDG&E's electric distribution system assets within the City. These costs are discussed in Appendix B, Section II.C.1 at 32 and are quantified in Section IV.F.5, below, and in the Appendix C, Section II.E.2 at 84-89. The MEU Study Team has estimated the acquisition costs of the distribution facilities at $170 million.

(2) Severance Costs

In addition to acquisition costs, the City will also be responsible for the payment of severance costs, which are incidental to the taking but are not attributable to the value of the property acquired. At this juncture, it is premature to make a detailed estimate of severance damages inasmuch as the final configuration of the MDU system and the reconfiguration of the SDG&E distribution system has not been determined. The MEU Study Team has made a preliminary estimate of severance and interconnection costs of $10 million. *See* Section IV.F.5 below at 126 and Appendix C, Section II.E.2 at 85. These costs are discussed in more detail in Appendix B, Section II.C.2 at 32-33.

(3) Interconnection Costs

In the absence of an agreement between SDG&E and the City respecting the interconnection of the City's municipal distribution system with SDG&E, and the reconfiguration of SDG&E's system to accommodate the interconnection, the Federal Energy Regulatory Commission will establish the terms and conditions of the interconnection, including the costs thereof. The City will be responsible for the payment of all costs related to the establishment of the interconnection. At this juncture, it is not possible to provide a detailed analysis of these costs. For purposes of this analysis, interconnection costs are combined with severance costs and estimated at $10 million (*see* Section IV.F.5 below and Appendix C, Section II.E.2 at 85). The methodology for establishing these costs is set forth in Appendix B, Section II.C.3 at 33-35.

(4) California Cost Responsibility Surcharge for Departing Load

On July 10, 2003, the CPUC issued Decision 03-07-028, "Order Adopting Cost Responsibility Surcharge Mechanisms for Municipal Departing Load," (Decision 03-07-028;

Limited Rehearing Granted in Decision 03-08-076 (collectively, the MDL Decisions)[73]. If Chula Vista forms an operating MEU and begins to generate power or purchase power from an entity other than SDG&E, according the MDL Decisions, it will be responsible for the payment of a surcharge for municipal departing load. While several interested parties have filed petitions for writ of review before the California Supreme Court (including one in which Chula Vista joined), as the law stands at this time, a surcharge will be applied to all municipal departing load, including new load served by Chula Vista. Inasmuch as the CPUC is still considering the level of these charges, the MEU Study Team has provided an estimate of these charges by proxy using the amount of the surcharge applicable to Direct Access customers, adopted by the CPUC in proceeding (R.02-01-011). Those costs are quantified in Appendix C, Section II.C at 78-81 and are discussed in more detail in Appendix B, Section II.C.4 at 35-39.

Under the MDL Decisions, the cost responsibility surcharge, or exit fee, will apply in all cases of CCA, Greenfield and MDU development. Those costs are discussed in more detail in Appendix B, Section II.C.4 at 35-39 and are quantified in Appendix C, Section II.C at 78-81.

5. Financing Options

Total costs for acquiring the distribution system are estimated at $185 million. These costs include the following:

Investment	Cost
Distribution Facilities	$170 Million
Interconnection/Severance	$10 Million
Regulatory/Litigation	$3 Million
Inventory	$2 Million
Total	$185 Million

The cost for the acquisition of distribution facilities assumes that the City does not elect to pursue the Greenfield development option. If that option is pursued, the distribution infrastructure costs of $12.1 million would be subtracted from the distribution system acquisition costs under the MDU option, to yield an acquisition cost of approximately $158.5 million.

Annual debt service to support this investment would be approximately $20.2 million at an assumed taxable debt interest rate of 6.5%.

[73] For more detailed information regarding the CPUC's "Exit Fee" proceeding and the municipal departing load cost responsibility surcharge, see Appendix B, Section I.C.1.b at 18-20.

Acquiring an interest in a generation project to support the Generation Strategy would require initial capital expenditures estimated at $78 million. This figure is derived based on an assumed ownership of 130 MW at an installed capital cost of $600,000 per MW. Annual debt service to support this investment would be approximately $5.4 million at an assumed tax-exempt debt interest rate of 5.5%.

The City would have a variety of financing mechanisms available to finance its MEU projects depending upon the specific asset and/or activity.[74] Financing techniques might include the following:

- General Obligation Bonds
- Limited Obligation Bonds
- Special Assessment
- Certificates of Participation
- Revenue Bonds
- Commercial Paper

6. Implementation Schedule

a. Major and Critical Steps

In the event that Chula Vista elects to form an MDU, the MEU Study Team has identified the following major and critical steps, beginning with a focused MDU Feasibility and Implementation Plan, which will be necessary for the City to complete before commencing the operation of the City's electric distribution system:

(1) Focused MDU Feasibility and Implementation Plan

(1.1) Distribution System Survey and Valuation: (1 mo.)
- 1.1.1 Detail the distribution system configuration, inventory equipment and facilities; document the percent condition
- 1.1.2 Perform a system valuation to determine just compensation for the negotiated purchase or condemnation of the existing distribution system

(1.2) Severance Plan and Cost Study: (3- mo.)
- 1.2.1 Perform an engineering evaluation of the distribution system within and adjacent to the City's boundaries

74 *See* Appendix C, Section IV at 126-27, for a detailed discussion of the differences, similarities, and applicability.

- 1.2.2 Document the location and configuration of substations and interconnections required to isolate and interconnect the City electric system and ensure SDG&E can provide service to its remaining customers
- 1.2.3 Prepare plans, specifications, drawings, material lists, cost and construction time estimates
- 1.2.4 Identify other private properties that must be purchased or condemned and estimate just compensation and time estimates

(1.3) Energy Resource Plan: (3 mo.)

- 1.3.1 Finalize generation and contract supply strategy, engage developers in negotiations
  - 1.3.1.1 Negotiate placement of generation facilities within City Boundaries
  - 1.3.1.2 Negotiate a percentage of plant ownership and/or entitlement to generation plant output
  - 1.3.1.3 Identify a short list of wholesale energy providers; refine supply pricing, terms and conditions of supply

(1.4) Human Resources Plan: (3 mo.)

- 1.4.1 Identify any areas of overlap with existing City organizational structures and ways to leverage existing staff capabilities
- 1.4.2 Re-evaluate human resource requirements (*see* Section IV.F at 106-07) to eliminate overlaps in staffing
- 1.4.3 Develop detailed job descriptions for each remaining human resource requirement
- 1.4.4 Perform an analysis of the regional labor base to determine availability of qualified candidates for key discipline areas Survey the relevant job market to fulfill plans to staff these positions and provide time estimates

(1.5) Facilities Plan: (3 mo.)

- 1.5.1 Identify facility requirements
  - 1.5.1.1 Customer and Energy Services: (call center, staff offices, billing system, vehicles and equipment)
  - 1.5.1.2 Distribution Engineering and Operations (offices, communication and control equipment, garage facilities, service vehicles, yard, security)
  - 1.5.1.3 Power Operations: (staff offices, systems and equipment)
  - 1.5.1.4 Detail availability, location and cost to build, buy, lease or otherwise acquire the needed facilities

(1.6) Pro Forma Update: (1 mo.)

1.6.1 Update cost estimates with results of the distribution system survey, severance, energy resource, human resources and facilities plans described in 1.1 to 1.5

1.6.1 Prepare request to SDG&E to obtain detailed customer load data

1.6.2 Update and refine load forecast based on planned development

1.6.3 Incorporate the impacts of any new regulations, cost assumptions or City objectives

(1.7) Finance Plan: (1 mo.)

1.7.1 Work with financial planners and bond counsel to develop revenue bonding and other alternatives for financing depending upon categories and values of assets to be financed

(1.8) Governance Plan: (2 mo.)

1.8.1 Propose governance structures for the new municipal utility

1.8.2 Obtain consensus among City leadership and establish plans for reporting, oversight and financial management of the municipal utility

(1.9) Implementation Plan: (1 mo.)

1.9.1 Incorporate all of the above into an implementation plan

1.9.1.1 Structures, costs, timelines, updated financial prospectus

1.9.1.2 Achieve City leadership's approval and move to Implementation Phase

(2) Implementation Phase Tasks

(2.1) Establish public interest and necessity and demonstrate greatest public good, least private injury (1 mo.)

(2.2) Ordinance No. 2835 has provided local authority establishing a public utility – further action by City Council to authorize negotiations with SDG&E as described in Section 2.3 below (1 mo.)

(2.3) Make an offer and attempt to negotiate the purchase of SDG&E's distribution system (1 mo.)

(2.4) Provide an opportunity for SDG&E to appear and be heard and argue public interest and necessity (30 days required - 1 mo.)

(2.5) Adopt Resolution of Necessity to condemn the property (1 mo.)

(Resolution of Necessity creates a rebuttable presumption that public interest and necessity have been established[75])

(2.6) Final Offer: 30 days prior to condemnation trial the City must make another attempt to negotiate the purchase of the property (1 mo.)

(2.7) Judicial Review:[76]

2.7.1 SDG&E is likely to seek judicial review of the validity of the City's Resolution of Necessity (see 2.5) before or during the power of eminent domain proceeding[77] (3 mo.)

(2.8) File Complaint in Superior Court invoking the power of eminent domain and initiating condemnation proceedings (6 mo. to 2-years):

2.8.1 Obtain any final information needed to confirm and support any critical elements of the Implementation Plan

2.8.1.1 The City can secure either the written consent of the SDG&E or an order from the Superior court to enter the property to make photographs, studies, surveys, examinations, and appraisals or engage in similar activities related to acquisition or use of the property[78]

2.8.1.2 If the City's Resolution of Necessity is accepted and the City's right to affect a taking of SDG&E's property and setting of compensation is approved, the City may apply ex parte to the court for an order for possession (deposit with the court the probable amount of compensation) and proceed to initiate the Implementation Plan.

(2.9) Execute Implementation Plan (1-year):

2.9.1 Negotiate the Date of Possession Based Upon the Scheduled Completion of the Following:

Governance Plan
Human Resources Plan
Facilities Plan

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75 Cal. Civ. Proc. Code § 1245.250

76 Cal. Civ. Proc. Code § 1245.255

77 Cal. Civ. Proc. Code §§ 1250.350 and 1250.370

78 Cal. Civ. Proc. Code §§ 1245.010, 1245.020, 1245.030

Severance Plan
Energy Resource Plan
2.9.2 Execute Energy Supply Agreements
2.9.2.1 - Finalize arrangements with developers for generation projects
2.9.2.2 Prepare RFP for Power Supply Contracts, Evaluate Responses and Execute Contracts
2.9.2.3- Begin Scheduling power

b. Timelines

Given the many variables inherent in the eminent domain proceedings and in the other regulatory proceedings related to the establishment of state imposed exit fees and nonbypassable charges, it is impossible to provide a definitive implementation schedule. The MEU Study Team estimates the following timelines for the completion of the planning elements and implementation phases in establishing an MDU:

Planning Elements: The time to complete additional planning, consisting of the individual elements itemized above, performed in sequence are estimated to take 20-months. However, overlaps and concurrent work projects might reduce this estimate to one-year. The lead time to implement generation projects, on which the MDU Generation Strategy option and its benefits are based, is estimated between one and one-half to three years, although this might be initiated prior to completing all of the planning elements.

Implementation Phase: It is estimated that the process leading up to a condemnation trial will take approximately six months for Implementation Tasks 7.(a) 2.1 through 2.7. The court hearings are estimated to take between six months and two years. An order for possession might be obtained prior to resolution and setting of just compensation. It is estimated that the City can establish its right to take the SDG&E assets by obtaining the judicial approval of the Resolution of Necessity within 10 months. It is further estimated that the implementation Plan can be fully executed in from one year to 18 months. Hence, the most optimistic time projection to implement the MDU is three and one-half years.

The MEU Study Team believes the estimated two year time required to implement a generation project will run concurrently with the additional planning activities and the condemnation process. Accordingly, the 3.5 year time estimate would not change for implementation of the MDU structure option with a Contract Supply Strategy. However, as discussed above, the MEU Study Team does not recommend implementing the MDU option with a Contracts Supply Strategy.

Based on the analysis contained herein, the City could elect to implement an MDU employing a Generation Supply Strategy as soon as it could obtain entitlement to generation output from a local, modern power plant. A phased approach, as described above, would allow the City to develop experience in the power procurement and delivery business.

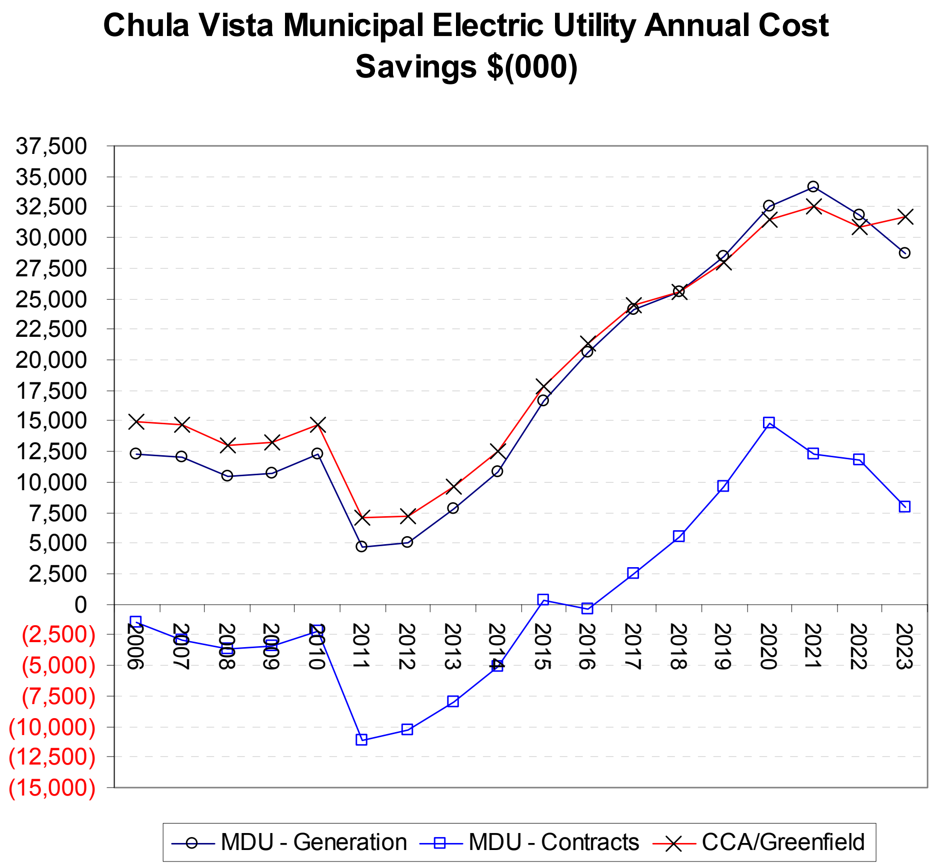
If the City elects to implement the MDU option in the 2010 timeframe, after the establishment of the Combined CCA/Greenfield option, as recommended by the MEU Study Team, the City would commence the MDU Planning and Implementation Elements discussed above in mid-2008.[79]

In considering the timelines necessary to implement an MDU system, the City should be cognizant of and prepared for strong legal and political opposition from SDG&E. Such opposition could substantially delay the completion of the acquisition process and increase the start-up costs for the MDU option.

7. Recommendation

As discussed above, the MEU Study Team has analyzed and evaluated the economic feasibility of an MDU option using both the Contract Supply Strategy and the Generation Supply Strategy. Those strategies have been compared with the Combined CCA/Greenfield development in the following chart:

[79] It should be noted that, in the Gantt Chart located in Section V.C at 171 and in Appendix C, Section V.C at 132, the implementation schedule used for comparing the MEU options reviewed herein begins in 2004 for all options.



As depicted above, the MDU based on a Contract Supply Strategy is much less advantageous to the City and does not begin to produce any tangible savings until 2017. The MDU with a Generation Supply Strategy, by contrast, will produce savings in every year during the study period. Although the Combined CCA/Greenfield option will produce more savings in the early years, the MDU with a Generation Supply Strategy may be the best long-term option open to the City when non-quantifiable benefits (i.e. local control resource, rates, and other decisions) are considered.

Based upon the positive results of the pro forma financial studies and the other major benefits, which will accrue from the implementation of the MDU (with the Generation Supply Strategy) option, the MEU Study Team believes that it is feasible, from both an economic and operational standpoint, for the City to form and operate an MDU by acquiring the distribution assets of SDG&E. In coming to this conclusion, the MEU Study Team recognizes that, because of the substantial capital investment required to acquire the distribution system, generation facilities and to defray the start-up expenses for an MDU, the potential NPV of benefits to the City is less favorable than the CCA/Greenfield option with a Generation Strategy. At the same time, the MEU Study Team is of the opinion that, in the long run, the ownership of the electric distribution system would allow the City to serve all electric customers within the City at rates substantially below the current and projected rates of SDG&E and permit the city to build asset value in the distribution system. The MEU Study Team has also given substantial weight to the non-financial benefits to be realized by public ownership of the distribution system, including local control of rates and service, discretion in the application of savings or benefits, and independence from SDG&E and the owner/operators of the transmission grid.

Given the additional planning and study requirements needed to implement the MDU option, together with the procedural steps which must be followed under the Eminent Domain Law, the MEU Study Team recommends that the City defer implementation of the MDU option until the 2008-10 time frame and re-evaluate the option based on circumstances existing at that time. Assuming that the City proceeds to develop the CCA and Greenfield options in the meantime, the City will have an MEU infrastructure, customer base, generation facilities and several years of operating experience before needing to make the critical decision of potentially acquiring the distribution system of SDG&E. In the event that CCA appears to be uneconomic once the CPUC has issued its final rulemaking decisions, the MEU Study Team would recommend that the City accelerate its consideration of the MDU option.

G. Joint Powers Agency/Municipal Utility District

In addition to the primary MEU options analyzed and evaluated in this feasibility analysis, the MEU Study Team has identified two additional long range options which the City might take advantage of once it establishes and commences the operation of a full service electric distribution system. These options, which are mutually exclusive, are (1) participation in a Joint Powers Agency (JPA), and (2) the formation of a Municipal Utility District (MUD) in coordination with another public entity. These options are discussed separately below.

1. Joint Powers Agency

a. Formation Requirements

If authorized by their legislative or other governing bodies, two or more public agencies by agreement may jointly exercise any power common to the contracting parties, even though one or more of the contracting agencies may be located outside of California. *See* Cal. Govt. Code § 6502.

The agreement to form a JPA shall state the purpose of the agreement or the power to be exercised. It shall provide for the method by which the purpose will be accomplished or the manner in which the power will be exercised. *See* Cal. Govt. Code § 6503.

Whenever a joint powers agreement provides for the creation of an agency or entity which is separate from the parties to the agreement and is responsible for the administration of the agreement, such agency or entity shall, within 30 days after the effective date of the agreement or amendment thereto, cause a notice of the agreement or amendment to be prepared and filed with the office of the Secretary of State. Such notice shall contain:

(a) The name of each public agency which is a party to the agreement.
(b) The date upon which the agreement became effective.
(c) A statement of the purpose of the agreement or the power to be exercised.
(d) A description of the amendment or amendments made to the agreement, if any.

If the JPA fails to comply with the notice requirements discussed above, it may not issue bonds or incur indebtedness until it complies. See Cal. Govt. Code § 6503.5

Once formed, and having complied with all applicable notice requirements, the JPA, as a separate public entity, commission or board, is authorized, in its own name, to do any or all of the following: to make and enter contracts, or to employ agents and employees, or to acquire, construct, manage, maintain or operate any building, works or improvements, or to acquire, hold or dispose of property or to incur debts, liabilities or obligations, said agency shall have the power to sue and be sued in its own name.

Any authorization pursuant to the agreement for the acquisition by the agency of property for the purposes of a project for the generation or transmission of electrical energy shall not include the condemnation of property owned or otherwise subject to use or control by any public utility within the state. *See* Cal. Govt. Code § 6508. Thus, with this limitation, the JPA could not acquire, by condemnation, the distribution system or other utility facilities of SDG&E. Chula Vista and its partners under the joint power agreement could exercise their own power of eminent domain to acquire utility assets and then dedicate the use of those facilities to the JPA. The JPA can own and operate both generation and transmission projects or facilities for the benefit of its members or, in the alternative, enter into power supply and transmission service agreements to complete the resource portfolio of its members.

b. Benefits

The JPA option would allow the Chula Vista MDU to accrue and realize further benefits by 1) the addition of partners to share the costs and risks of the MDU option; 2) possible aggregation of a larger load for resource procurement purposes, which, in turn, would lead to possible lower purchase power costs; and 3) possible reductions in cost for other activities associated with running an electric utility such as operation and maintenance functions.

First, because a JPA is likely to spread the costs and risks associated with the provision of electric utility services, the direct exposure of the City may be minimized. At the same time, key capital, political, and intellectual resources could potentially be "tapped" from the other JPA members. Second, in developing a financial case for a JPA venture, the larger the electric load the more viable the prospect of cost-savings. This is due mainly to the fact that the JPA load can be substantially larger. Third, although a JPA cannot own distribution facilities, it could construct generation facilities, purchase power through long-term contracts, sell any excess electric power on the open market, acquire transmission facilities or enter into contracts for transmission service with transmission providers including SDG&E and the CAISO, lease office space, issue bonds and incur indebtedness and provide customer services such as metering and billing functions.

c. Risks

Since JPAs are not allowed, under applicable law, to acquire and own electric distribution facilities, a JPA model is not useful to the City until it establishes a full service electric distribution system. Thus, the JPA is not a substitute for an MDU. There are certain inherent obstacles and down-side risks in the formation of a JPA structure. Specifically, the City may be faced with the following practical problems in forming a JPA:

- The formation of the JPA may be much more time-consuming than the development of a city department approach. It will be necessary to establish some form of work group or advisory panel of the participating members, and ultimately members would need to agree on strategy for developing a viable JPA structure with reasonable and achievable goals.

- The decision-making process of the JPA structure may prove much more cumbersome than under the city department model. This is true during both formation and operation of the JPA. Each member would be seeking to protect its own interests, and these interests may not necessarily coincide with another member's interests or the group's interests as a whole. This could result in the JPA not being able to provide the same benefits or allow the new electric utility to be as "nimble" as the city utility department option.

- The potential of a protracted legal fight with SDG&E may also limit the enthusiasm of potential parties to the JPA if Chula Vista elects to acquire the distribution system of SDG&E and, at the same time, participate in a JPA. The larger the potential service territory (customers and load), the more likely it is that SDG&E will aggressively oppose the formation of a new utility or JPA.

2. Municipal Utility District

a. Formation Requirements

A Municipal Utility District (MUD) may be formed by either Resolution or Petition[80] to the Board of Supervisions of the County containing the largest number of voters within the proposed MUD.[81]

In the case of formation by Resolution, the legislative bodies of the entities seeking to form the MUD must adopt resolutions which declare that MUD formation is necessary and in the public interest. The resolution must state the type of utility to be acquired and describe the exterior boundaries of the District or a list of public agencies included if the District is made up of public agencies only. The Resolution must also include a request for an election and be certified to the Board of Supervisors of the County containing the largest number of voters within the proposed District.[82]

In the case of a request by Petition, a Petition must be presented by the forming public entities to the Board of Supervisors of the County containing the largest number of voters

[80] Cal. Pub. Util. Code § 11562.

[81] *Id.*, § 11583.

[82] Cal. Pub. Util. Code § 11581-11583.

within the proposed District. The petition must be signed by at least 10% of the voters within the proposed District which voted in the last preceding general election. Signatures must be verified.

Once a Resolution or Petition is filed with the Board of Supervisors, an election must be held within seventy-four (74) days after the date of the order calling for an election. An affirmative vote of two thirds of the registered voters within the proposed District will authorize the establishment of the District. The Board of Supervisors shall file a certified copy of the order declaring that result of the election to be filed with the Office of the Secretary of State, after which the establishment of the District will be complete.

The internal organization of a Municipal Utility District, including government, election of directors, additional directors, terms of office of directors, powers and duties of directors, meetings and legislation, other officers, and initiative and referendum is governed by Cal. Pub. Util Code §§ 11801-11950.

b. Benefits

Similar to the city utility department model, the MUD option could offer residents within the City of Chula Vista many benefits, including the likelihood of lower-priced power, more stable electricity rates, local control, and improved reliability. By selecting the MUD utility structure option and combining City electric loads and service area with those of other cities or unincorporated territories, an additional benefit would be the ability to secure more competitively priced power by combining the energy needs of more residents and business, thereby lowering the price of utility services, on a per unit basis, for all customers within the MUD. Other economies of scale opportunities could also potentially be realized through the purchase of distribution facilities or other assets such as utility vehicles and sharing administrative costs. There are also possible reductions in disconnection costs from the SDG&E system.

c. Risks

One of the impediments of the MUD structure, as opposed to the city department structure, is that the City must come to an agreement with one or more other municipal agencies in developing the terms and conditions of establishing the MUD. Competing issues could arise that must be resolved before the MUD could become operational. In some instances, the resolution of such an issue might not be as beneficial to the City when compared to an independent utility structure.

Forming an MUD by combining the territories of other cities and/or unincorporated territories with the City would require approval of the San Diego County Local Agency Formation Commission (LAFCO). The LAFCO approval process generally adds complexity and uncertainty when compared to the formation process for the municipal electric utility department described above, while still including all of the impediments described in the City department option.

For these reasons, the MEU Study Team does not recommend using the MUD structure as a substitute for the formation of the City's own MDU. The formation of an MUD involves a number of additional uncertainties and complexities in addition to those already inherent in the formation of an MEU. Moreover, in broadening the MEU option to include other public entities or unincorporated areas, as required under the MUD structure, the City would lose a considerable amount of local control and autonomy. Rather, the MEU Study Team recommends that once the City exercises its option to establish its own MDU, it examine the option of forming an MUD in collaboration with other public entities.

3. Implementation Schedule

Since the MEU Study Team has recommended that both the JPA and MUD options be considered as long range options to be further evaluated after the City exercises its options to establish its own MDU, no implementation schedule has been developed for either of these options.

4. Recommendation

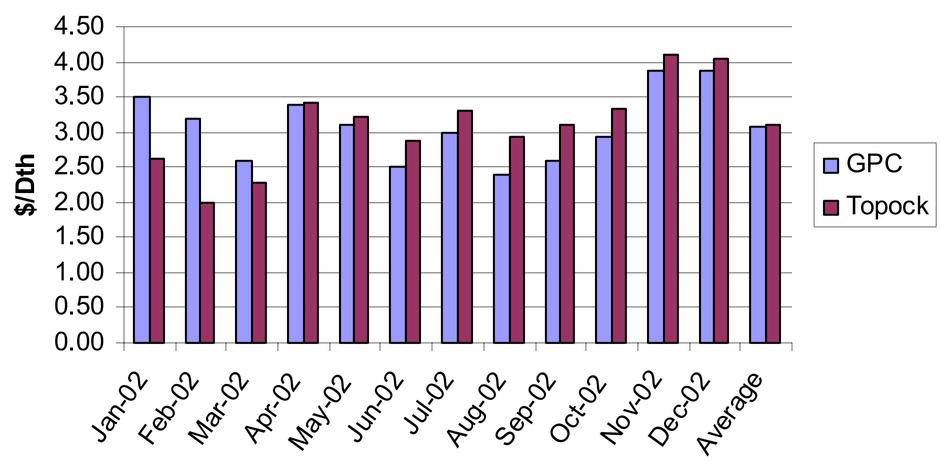
The MEU Study Team recommends that, if the City has exercised its option to establish and commence the operation of a full service MDU, it should give serious consideration to joining (or forming) a JPA with other publicly-owned utilities or forming an MDU with another public entity, community or unincorporated area. In using these vehicles, the City may be able to spread risk, enjoy the further benefits of the economies of scale, enlarge its electric resource portfolio, and realize further savings and benefits.

H. Natural Gas

1. Feasibility of Acquiring Gas Distribution Facilities in Chula Vista

This section presents an analysis of the feasibility of owning and operating the gas distribution facilities located within the City of Chula Vista. These facilities are currently owned by SDG&E, a wholesale customer of SoCal Gas whose rates and tariffs are subject to CPUC regulation. The analysis focuses on the economics of the gas distribution business since, as shown in Figure 1, SDG&E's gas procurement charge for core customers (Schedule GPC) is competitive with the market price of gas at the California border at Topock. Moreover, SDG&E does not own substantial amounts of interstate pipeline capacity or gas procurement contracts that are likely to be "above market" under reasonable market conditions. Consequently, the feasibility of entering the gas business will hinge almost entirely on whether Chula Vista can provide a benefit from acquiring, owning, and operating the gas distribution facilities within the city's boundaries. To provide a benefit, Chula Vista would need to provide gas transportation and distribution (T&D) services to customers at a lower cost than the customers currently pay to SDG&E. As this analysis demonstrates, it is not economically or financially feasible for the City to undertake providing gas service to customers within the City.

Figure 1: SDG&E GPC vs. Topock Index Price



The following sections discuss the methodology and assumptions used by the MEU Study Team to forecast Chula Vista's T&D costs and compare them with SDG&E's costs.

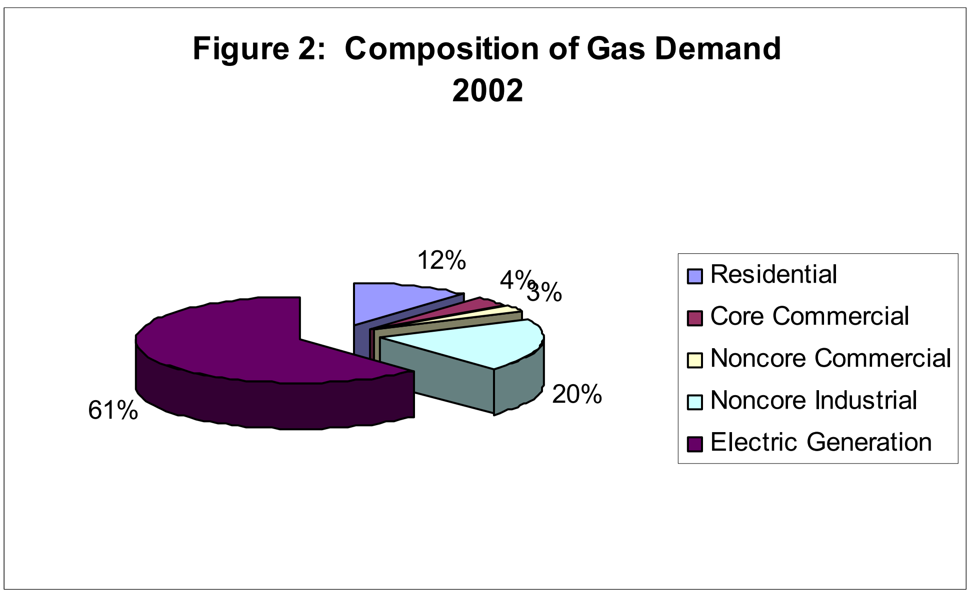
2. Gas Demand Forecast

Table 1 provides a breakdown of Chula Vista's annual gas requirements by number and type of customers. The table was estimated by the MEU Study Team based on data provided by Chula Vista and SDG&E statistics. In 2002, customers located in Chula Vista consumed approximately 177 million therms of gas and provided net revenues of $24.5 million to SDG&E. In 2002, Duke Energy's South Bay Power Plant, a transportation-only customer of SDG&E, accounted for nearly two-thirds of total consumption but only 8.5 percent of total revenue ($2.1 million). The power plant's small revenue share reflects the low ($0.019 per therm) Sempra-wide gas transportation rate paid by all electric generation (EG) customers in southern California in 2002. In contrast, Chula Vista's 62,500 residential users, who paid an average bundled (commodity plus transportation) rate of nearly $0.70 per therm, accounted for 12 percent of total consumption and 58 percent of total revenue. Core commercial customers (3.6 percent of consumption, 21 percent of revenues) and noncore industrial customers (20 percent of consumption, 10.3 percent of revenue) accounted for most of the remaining sales and revenue. Residential and commercial core customers take bundled procurement plus transportation service from SDG&E. Both noncore customer classes take transportation-only service.

To forecast future gas consumption, the MEU Study Team escalated the number of residential and commercial customers by an average of 1.7 percent per year, the same growth rate used in the MEU Study Team's electricity analysis. As a result, by 2023, the number of residential and core commercial accounts grows to 86,818 and 4,685, respectively. The number of large energy-intensive noncore industrial users is held constant, on the assumption that the number of new entrants equals the number of existing accounts that close down owing to regional and global competition.

Table 1
Composition of 2002 Chula Vista Gas Demand

	No. Customers	2002 Therms	Therms per Customer	Net Revenue $	$/Th	Avg SDG&E Tariff Rate 2002	Type of Service
Residential	62,500	20,600,359	330	$14,200,760	$0.6893	0.70255	Bundled
Commercial, total	3,390	11,365,569	3,353	$5,665,909	$0.4985		
Core Commercial	3,370	6,365,569	1,889	$5,115,909	$0.8037	0.72784	Bundled
Noncore Commercial	20	5,000,000	250,000	$550,000	$0.8037	0.09582	Bundled
Industrial & EG, Total	11	144,962,110	13,178,374	$4,621,786	$0.0319		
Noncore Industrial	10	34,778,410	3,477,841	$2,528,663	$0.0727	0.07764	Transport-only
Electric Generation	1	110,183,700	110,183,700	$2,093,123	$0.0190	0.01900	Transport-only
Total	65,901	176,928,038	2,685	$24,488,455	$0.1384		



Consistent with the assumption made in the electricity analysis, the MEU Study Team assumed that residential gas use per customer would remain relatively flat over the next 20 years while core commercial use per customer would increase 0.5 percent per year. Multiplying the change in gas use per customer by the change in customer numbers yields a forecast of gas consumption through 2023. In the forecast, residential consumption expands 36 percent to 28 million therms per year by 2023, while core and noncore commercial usage expands 54 percent to 17.5 million therms per year (versus 11.4 million therms in 2002). Noncore industrial usage remains a constant 34.8 million therms per year.

To forecast gas supply for power plant usage, the MEU Study Team assumed that the South Bay Power plant would continue to operate as a must-run unit through 2006. During this period, the plant's annual generation is assumed to increase at the same 2.5 percent annual rate as SDG&E's overall electricity requirements. Assuming a constant heat rate of about 10,000 Btu/kWh, gas consumption by South Bay is estimated to grow to 124 million therms per year by 2006. In 2007, two new, highly efficient combined cycle power plants (Otay Mesa and Escondido) are assumed to start up. (Since South Bay's current configuration and attendant cost of operation would not be competitive with the new Otay Mesa and Escondido plants, the MEU Study Team did not include South Bay's gas requirements in this analysis.) As a result, electric generation (EG) gas requirements fall to zero in 2007 and 2008. In 2009, the MEU Study Team assumes a new electric generating plant is constructed within the boundaries of Chula Vista to replace the existing South Bay power plant. Assuming that the plant has a heat rate of 7,000 Btu/kWh and operates at a 70 percent capacity factor, annual gas consumption is projected to be a constant 257,544 therms per year from 2009 through 2023.

Under the above assumptions, total gas consumption by consumers in Chula Vista grows to nearly 338 million therms per year in 2023, 91 percent greater than in 2002. As at present, power generation continues to account for the lion's share of forecasted gas demand.

Table 2
Gas Demand Forecast

Sector	2002 Therms	2023 Therms	% Increase	% of Total
A. Residential	20,600	28,075	36%	8.3%
B. Core Commercial	6,366	9,827	54%	2.9%
C. Noncore Commercial	5,000	7,719	54%	2.3%
D. Noncore Industrial	34,778	34,778	0%	10.3%
Subtotal R/C/I	66,744	80,399	20%	23.8%
E. Electric Generation	110,184	257,544	134%	76.2%
Total Requirements	176,928	337,943	91%	100.0%

3. SDG&E Gas Transportation Revenue

The MEU Study Team next estimated the annual revenue SDG&E would receive from delivering gas to customers in Chula Vista during the forecast period. As noted above, the analysis focused only on gas distribution and transmission revenue based on our assumption that a municipally owned gas utility in Chula Vista would provide gas procurement service at roughly the same cost as SDG&E. This required a forecast of SDG&E's gas transportation and distribution (T&D) rates through 2023, including SDG&E's cost of wholesale gas transportation on the SoCal Gas system.

SDG&E's rates were forecast by escalating average 2002 rates (excluding commodity) by the annual escalation factors assumed to result from continuation of SDG&E's CPUC-approved performance-based ratemaking (PBR) mechanism. Under the current PBR, SDG&E is permitted to increase rates each year by the rate of inflation minus a factor for productivity gains and a "stretch" factor intended to encourage efficient utility operation. If actual costs increase by less than the allowed increase in rates, the savings are shared between SDG&E and its customers according to a formula. In 2003, the existing PBR mechanism has resulted in annual rate increases of 2.6 percent.

In its current General Rate Case (GRC) (Application 02-12-028), SDG&E is proposing to modify the PBR mechanism so that the annual increase is applied to base margin (essentially, T&D revenue) rather than rates per se. SDG&E argues that, due to the increase in efficiency observed since California's energy crisis and the results of CPUC-approved efficiency programs, usage per customer is growing more slowly than in the past. Consequently, according to SDG&E, the rate escalation method produces smaller revenue increases than were intended when the PBR mechanism was designed. SDG&E proposes to address this issue by escalating base margin by inflation minus a productivity factor and add the increase in miscellaneous revenues due to inflation (currently outside the PBR mechanism). Rates would be calculated by dividing the escalated revenues by forecasted sales.

Since it is uncertain whether SDG&E's proposal will be adopted, the MEU Study Team escalated SDG&E's rates by an average of the escalation factors expected to result from extension of the current PBR mechanism and adoption of the proposed mechanism. This yields an average escalation rate of 1.6 percent per year. The MEU Study Team's forecast of SDG&E rates is presented in Table 3. Under this forecast, SDG&E's rates are projected to increase between 1.5 and 3.5 percent per year through 2023 in nominal terms.

Table 3
Forecast SDG&E Gas Transportation & Distribution Rates
($/Therm)

Sector	2002 Rate	2023 Rate	Annual % Inc.
A. Residential	$0.394	$0.592	2.1%
B. Core Commercial	$0.420	$0.560	1.5%
C. Noncore Commercial	$0.078	$0.121	2.2%
D. Noncore Industrial	$0.078	$0.121	2.2%
E. Electric Generation	$0.019	$0.038	3.5%

As shown in the Table, core residential and commercial users currently pay an average T&D rate of about $0.40 per therm ($4.00 per Dth), five times the rate paid by noncore commercial and industrial users. EG customers pay the lowest rate, $0.019 per therm ($0.19 per Dth). The low EG rate is partly a result of the fact that most EG customers take service from high-pressure gas transmission lines and thereby "avoid" the more costly low-pressure pipelines that distribute gas to smaller residential and commercial users. In addition, in Decision 00-04-060 (issued April 2000), the CPUC adopted a Sempra-wide EG rate that equalizes the gas transportation rates for EG customers on the SoCal Gas and SDG&E systems. As shown in Table 4, the adoption of a Sempra-wide EG rate lowered the transportation rate for generators in San Diego roughly $0.012 per therm (26 percent) below the rate that would have resulted from the previous, stand-alone rate method. As discussed below, by reducing South Bay's transportation rate, the new rate mechanism makes it difficult, if not impossible, for Chula Vista to serve the power plant at a profit. The MEU Study Team's analysis assumes that the Sempra-wide EG rate will remain in place in the future, a reasonable assumption given the CPUC's goals of promoting a "level playing field" for electric generators in the southern part of the state. The MEU Study Team recommends that, if the Sempra-wide EG rate changes dramatically between 2006-2008, the City reconsider the feasibility of providing gas service.

Table 4
Sempra-Wide EG Rate (2000 BCAP)

Sempra-wide vs. Stand-alone EG Rate ($/Therm)	$/Therm
(1) Est Stand-alone rate	$0.046
(2) Sempra-wide EG rate	$0.034
Difference	$0.012
Ratio (2)/(1)	0.744
% Difference	25.6%

Multiplying forecasted sales by forecasted rates yields an estimate of the revenues Chula Vista customers would pay to SDG&E for delivering gas over the next 20 years. The revenue forecast is presented in Table 5 below.

Table 5
Forecast SDG&E T&D Revenue from Chula Vista
(000 $)

Sector	2002 (000$)	2023 (000$)	Annual % Inc.
A. Residential	$8,112	$16,621	3.7%
B. Core Commercial	$2,671	$5,500	3.7%
C. Noncore Commercial	$388	$935	4.5%
D. Noncore Industrial	$2,700	$4,212	2.2%
Subtotal Res/Comm/Ind	$13,871	$27,267	3.4%
Average $/Therm	$0.208	$0.339	2.5%
E. Electric Generation Revenue	$2,093	$9,769	8.0%
Total Revenue	$15,964	$37,036	4.3%
Total Average $/Therm	$0.090	$0.110	1.0%

By 2023, the MEU Study Team forecasts that Chula Vista customers will pay SDG&E a total of $37 million per year for gas delivery services, an increase of 4.3 percent per year over 2002 revenues of $16.0 million. For gas utility acquisition to be cost-effective, Chula Vista must be able to deliver gas to customers for less revenue than SDG&E.

4. Estimate of Chula Vista Operating Cost

To provide a preliminary estimate of Chula Vista's cost of providing gas delivery service, the MEU Study Team analyzed the revenues and costs of the two largest municipal gas utilities in California: Long Beach Energy (Long Beach) and the City of Palo Alto Utilities Department (Palo Alto). To further validate the results of this analysis, the MEU Study Team benchmarked the non-gas revenues (i.e., revenue excluding commodity costs) of a representative panel of municipally owned gas utilities in other parts of the United States. The result is a reasonable, first-order, approximation of what it might cost Chula Vista to operate a gas distribution utility in its service area.

Table 6 presents the gas delivery costs of Long Beach and Palo Alto based on financial data reported by each city. Excluding transfers to the General Fund (GF), Long Beach's cost of delivering gas to its 144,000 customers was $0.153 per therm in the fiscal year (FY) ending September 30, 2002 (FY 2001-02). The corresponding figure for Palo Alto was $0.24 per therm, based on data for the FY ending June 30, 2000. The average T&D cost for both utilities was $0.196 per therm.

Table 6
Long Beach and Palo Alto Gas Delivery Costs

	Long Beach	Palo Alto	Average
Year	FY 2001-02	FY 1999-2000	
No. Customers	144,000	23,400	
Gas Thruput at City Gate 000 Therms	109,372	36,360	
Total Operating Expense 000$	54,474	22,787	
Gas Commodity Cost 000$	29,861	11,595	
T&D Cost 000$	24,613	11,192	
General Fund Transfer 000$	7,851	2,475	
Capital Improvement Prog (CIP) 000$	0	2,858	
T&D Cost excl GF Trans	16,762	8,717	
Delivery Cost per Therm	0.153	0.240	0.196
GF Transfer as % T&D Revenue	47%	28%	38%
GF Transfer as % Total Revenue	14%	11%	13%

Source: Long Beach Comprehensive Financial Plan, p. 38;
Palo Alto Adopted Budget 2001-2003 and PAU staff data.

To supplement the above analysis, the MEU Study Team compiled data on the non-gas revenues of four other municipal gas utilities from 1995 through 2000.[83] The utilities are Richmond, VA, San Antonio, TX, Springfield, MO, and Citizens Gas and Coke of IN. The analysis examined revenue from residential, commercial, and industrial customers, the same classes of customers that would be served by Chula Vista. Revenue from EG customers was excluded to provide an apples-to-apples comparison with Long Beach and Palo Alto, which do not serve EG customers. Figure 3 compares the number of customers and annual non-EG throughputs for four panel members plus Palo Alto and Long Beach. As shown on the left-hand scale, the utilities serve from 23,000 (Palo Alto) to 300,000 customers (San Antonio). Residential, commercial, and industrial throughput ranged from 36 million therms (Palo Alto) to nearly 500 million therms (Citizens Gas & Coke). Given the breadth and geographical diversity of the sample, we believe that it provides a reliable basis for estimating the costs of operating a municipal gas utility in Chula Vista.

[83] The data were obtained from SNL Securities, a software services company which maintains a computerized database of EIA and other data that can be sorted by the user. EIA data can also be downloaded from the agency's website.

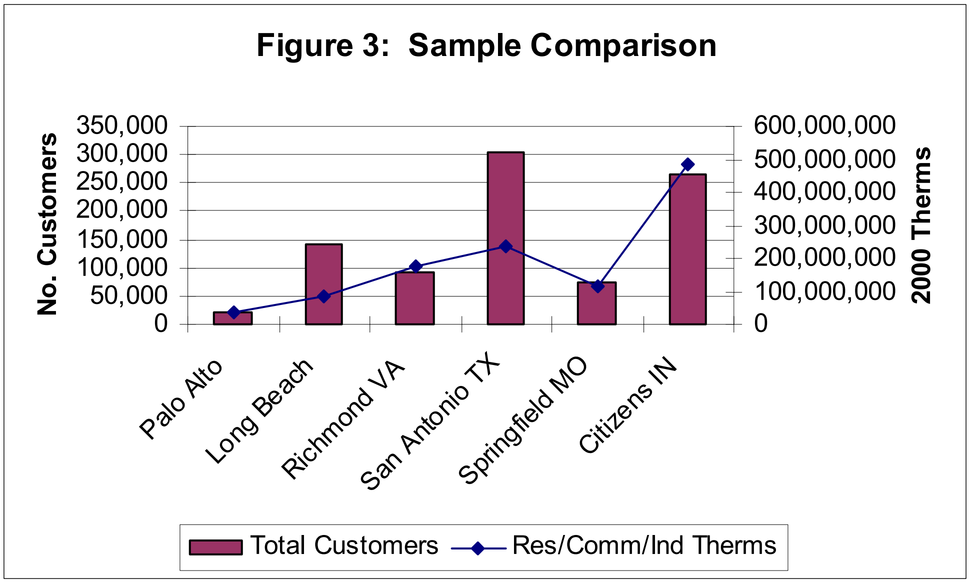
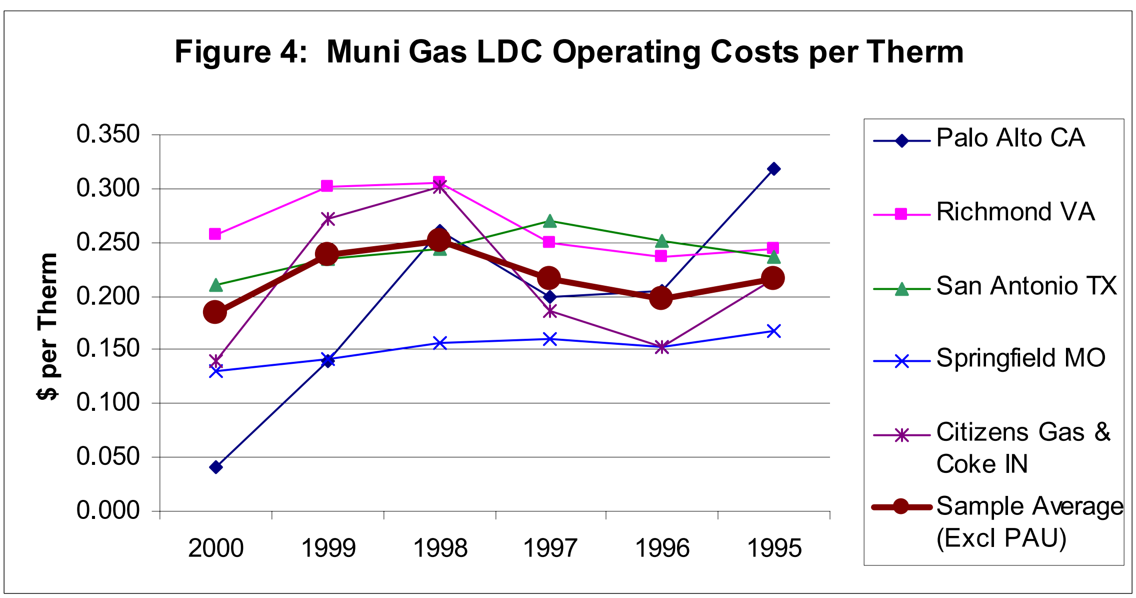


Figure 4 provides the non-gas revenue per therm (total revenue minus gas commodity costs) of the panel members from 1995 to 2000. General Fund (GF) transfers are not reported to EIA and, hence, cannot be netted out of the analysis to estimate T&D costs as was done for Palo Alto and Long Beach. The heavy line at the center of the graph does, however, provide the average non-gas revenue for each year. From 1995 to 2000, average non-gas revenue for the panel members ranged from $0.18 to $0.25 per therm. The period average was $0.22 per therm.



To provide an estimate of Chula Vista's operating costs, the panel data must be adjusted for GF transfers. As shown in Table 6, GF transfers averaged 38 percent of non-gas revenue for Long Beach and Palo Alto. This figure is substantially higher than the historical average for all U.S. municipal gas utilities, which the MEU Study Team estimates to be in the range of 10 percent of total revenue or about 25 percent of non-gas revenues. For the purpose of a conservative analysis, the MEU Study Team assumed that the four panel members transferred an average of 30 percent of non-gas revenue to their General Funds during the 1995 to 2000 period. Operating expenses were assumed to comprise the remaining 70 percent. Based on this assumption, average T&D revenue for the panel would be $0.15 per therm. In the MEU Study Team's view, this is a reasonable proxy for the cost of providing gas delivery services to residential, commercial, and industrial customers in Chula Vista. The estimate is comparable to the figure estimated for Long Beach, but lower than Palo Alto's T&D cost in FY 1999-2000. This further underscores its reasonableness as the basis for a preliminary analysis of Chula Vista gas utility feasibility.

The preliminary analysis assumed that Chula Vista could serve the South Bay power plant for $0.001 per therm ($0.01 per Dth). The estimate assumes that the power plant is served from a relatively short lateral pipeline that connects directly to the main transmission line traverses Chula Vista along Interstate 5. The MEU Study Team further assumed that this pipeline would not require any significant maintenance or upgrading during the entire forecast period. This is probably a reasonable estimate until the power plant is expanded in 2008-09, but it likely understates the cost of serving an expanded power plant. However, since an engineering analysis of the condition of the lateral and potential upgrade costs was beyond the scope of the MEU Study Team's analysis, we were unable to determine a more precise estimate of this potentially important variable.

Based on the above assumptions, annual operating costs are estimated to be $10.4 million in 2003, including $113,000 to serve the power plant. Chula Vista's operating costs were assumed to increase by 3 percent per year through 2023.

5. SoCal Gas and SDG&E Transmission Costs

To transport gas from the California border to its City Gate, Chula Vista would need to pay SoCal Gas' wholesale rate for SDG&E plus the cost of transporting gas from the SoCal Gas-SDG&E meter station to Chula Vista. SoCal Gas' wholesale transmission rate is presently $0.018 per therm ($0.18 per Dth). While SDG&E does not currently have a gas transportation rate for wholesale customers on its system, a proxy for this rate was calculated by dividing SDG&E's total transmission cost of service by its total annual throughput. In its decision in SDG&E's 2000 BCAP (D.00-04-020), the CPUC adopted an embedded transmission cost of $33 million for SDG&E. Dividing by annual throughput of 1.441 billion therms, the per unit rate works out to $0.023 per therm ($0.23 per Dth). Based on the MEU Study Team's forecast of Chula Vista gas throughput, the annual cost of SoCal Gas and SDG&E transportation service was estimated to be $7.36 million in 2003. These costs were escalated by 1.6 percent per year, the same factor used to estimate future SDG&E's retail transportation rates.

6. Capital Cost Estimate

Consistent with the analysis of electric utility ownership, the MEU Study Team assumed that Chula Vista would acquire the SDG&E gas T&D facilities located in Chula Vista for 1.64 times the net book value (depreciated rate base) of the facilities. The depreciated rate base of the Chula Vista facilities was estimated to be $20.5 million, 4.8 percent of the total net book value of SDG&E's gas plant in service at the end of 2002 ($423.2 million). Chula Vista's percentage was based on its share of SDG&E's total non-EG throughput. This effectively attributes minimal value to the transmission facilities used to serve the South Bay power plant. Multiplying net book value by 1.64 yields an estimated acquisition cost of $33.5 million.

Utility start-up costs were conservatively estimated to be 15 percent of the total acquisition cost or $5.0 million. This is a preliminary estimate that would only cover the cost of acquiring the land, buildings, office equipment, stores, and other items needed to form a gas distribution utility in Chula Vista. Start-up costs could turn out to be significantly greater if additional metering facilities, regulating stations, or other systems are required to commence utility operations.

The MEU Study Team assumed that the City would issue 30-year bonds to finance the acquisition and start-up costs. At an interest rate of 6.5 percent, the annual principal and interest cost is $418,000 per year. Annual capital investment costs are estimated to be $958,000 per year in 2003, equivalent to the annual depreciation allowance assuming straight-line depreciation over a 35-year period.

7. Estimated Benefit of Utility Ownership

Table 7 summarizes the results of the MEU Study Team's preliminary analysis of the feasibility of gas utility ownership in Chula Vista. As shown on Line 10, under the assumptions used by the MEU Study Team, the total operating and capital cost of providing gas delivery service to Chula Vista customers in 2003 is estimated to be $19.1 million, or $0.106 per therm. The estimated cost of utility ownership is $777,000 greater than our estimate of the revenues Chula Vista gas users would pay to SDG&E for these services. Upon establishing a municipal utility, Chula Vista would cease receiving franchise fees from SDG&E. Based on the 2.0 percent rate indicated in the franchise fee estimates provided to the MEU Study Team, the lost franchise fee is estimate to be $657,000 in 2003. The total loss from utility operations is thus $1.43 million in 2003. Based on the cost escalators and throughput estimates presented above, the total loss is projected to grow to $3.6 million in 2010 and $7.0 million in 2023. Over the study period, the MEU Study Team estimates that the City would lose approximately $24 million if it were to acquire the gas distribution system of SDG&E and provide gas service to customers within the City.

Table 7
Estimated Benefits of Gas Utility Ownership in Chula Vista

Line		2003	2010	2015	2023
1	C.V. Delivery Cost to R/C/I ($/Therm)	$0.152	$0.187	$0.217	$0.275
2	Cost to Serve R/C/I (000$)	$10,294	$14,053	$16,827	$22,102
3	Est. Cost to Serve Power Plant ($/Th)	$0.001	$0.001	$0.001	$0.002
4	Cost to Serve Power Plant (000$)	$113	$317	$367	$465
5	SoCalGas Wholesale Rate ($/Th)	$0.018	$0.020	$0.021	$0.024
6	Est. SDG&E Trans. Rate ($/Th)	$0.023	$0.026	$0.028	$0.032
7	SoCalGas/SDG&E Cost (000$)	$7,361	$15,174	$16,557	$18,963
8	Capital Expense (000$)	$418	$418	$418	$418
9	Capital Improvement Cost (000$)	$958	$958	$958	$958
10	**Total Expenses**	**$19,145**	**$30,920**	**$35,127**	**$42,907**
11	$/Therm	$0.106	$0.093	$0.105	$0.127
12	**Estimated SDG&E Revenue**	**$18,368**	**$28,157**	**$31,475**	**$37,036**
13	**SDG&E Revenue minus CV Cost**	**($777)**	**($2,763)**	**($3,652)**	**($5,872)**
14	Lost Franchise Fee	$657	$885	$978	$1,146
15	**Net Benefit/(Cost)**	($1,434)	($3,648)	($4,630)	($7,017)

8. SDG&E BCAP Proposal

On September 17, 2003, SDG&E issued a Notice of Proposed Change to Gas Rates (Notice) informing customers of proposed increases in natural gas transportation rates effective January 1, 2005. The proposed rate changes are contained in SDG&E's 2005 Biennial Cost Allocation Proceeding (BCAP) in CPUC docket A.03-09-031. The Notice was posted on SDG&E's website and is being mailed to customers along with their natural gas bills. According to the Notice, SDG&E is seeking relatively modest increases in bundled rates (i.e., including commodity charges) for core residential and commercial customers, which would rise by five and 16 percent over current levels, respectively. In contrast, noncore industrial and electric generation customers would see rate increases of 67 and 81 percent, respectively.

Since SDG&E's gas transportation revenue requirement is proposed to increase only 13.5 percent, it appears that the majority of the increase in noncore rates will result from a proposal to replace the current marginal cost allocation methodology with an embedded cost methodology. Marginal cost ratemaking (adopted by the CPUC in the early 1990s) tends to assign a higher percentage of the utility's fixed costs to customer classes (especially core) that require the most costly facilities to serve. Thus, a return to embedded cost ratemaking would be consistent with the modest rise in core rates and the sharp increases in noncore rates described in the Notice. Such huge rate increases pose risks for SDG&E, since the largest noncore customers (particularly power generators) could be temped to switch to alternative fuel or take service from competing pipelines. Customers in highly competitive product markets could also be forced out of business if they are unable to pass along the proposed rate increases to their customers. To mitigate such risks, SDG&E is proposing "100 percent balancing account treatment" of noncore transportation revenues (i.e., any revenue shortfalls due to lower throughput or customer bypass will be recovered by raising rates for subsequent periods). Both proposals are likely to be highly controversial and strongly opposed by noncore customer representatives. At this time, it is impossible to predict how the Commission will respond to this application.

It is similarly uncertain how the CPUC will respond to the concurrent application by Southern California Gas Company (SoCal Gas) to make similar changes in its rates and balancing accounts. If approved SoCal Gas' BCAP application (A.03-09-008) would more than double the wholesale gas transportation rate charged to SDG&E. Since the wholesale rate is a major cost component for Chula Vista, approval of both the SoCal Gas and SDG&E BCAP applications could have offsetting impacts on Chula Vista. While gas consumers in Chula Vista would pay higher rates to SDG&E, the rates Chula Vista would pay to SoCal Gas and SDG&E to transport gas to its City Gate would also rise. Until the BCAP proceedings are much further along, it would be speculative to assess the net impact of these changes on Chula Vista.

In the meantime, the MEU Study Team's detailed analysis of Chula Vista's gas costs and rates remains a sound basis for determining if gas utility formation would be cost effective in Chula Vista.

9. Conclusions

The MEU Study Team's preliminary analysis concludes that gas utility ownership would not be cost-effective for Chula Vista. The major factors that drive this result include the following:

(1) SDG&E's gas procurement costs are competitive with spot market prices at the southern California-Arizona border at Topock. SDG&E owns relatively limited interstate pipeline capacity that could become uneconomic under reasonable market conditions. In addition, since SDG&E buys most of its gas under short-term contracts or contracts indexed to spot market prices, there is little potential for gas contract costs to rise substantially above prevailing market prices. Under these conditions, there is little potential to earn a benefit from gas supply aggregation in Chula Vista.

As a result, the economics of gas utility operation hinge on whether Chula Vista can serve its potential customers for less than SDG&E.

(2) SDG&E is an efficient transporter of natural gas to its retail customers. SDG&E's cost performance was documented by a benchmarking study filed with the CPUC in the company's pending GRC (A.02-12-028).[84] The study benchmarked SDG&E against a national panel of 42 gas distributors that collectively serve 52 percent of U.S. gas customers. The panel included most of the nation's largest distributors. The study found that SDG&E's productivity during the 1998-2000 period was 33 percent above the norm and ranked first among the sampled LDCs. SDG&E's average total cost of distribution services was also reported to be 37 percent below the costs predicted by the consultant's econometric model for this period. Another indicator of SDG&E's cost competitiveness is the fact that its system average rate is only 3.3 percent higher than that of its sister company, SoCal Gas, a utility with total throughput 6.6 times greater than SDG&E. The reported efficiency of SDG&E will make it that much harder for a new gas utility to provide comparable service at a lower cost.

(3) Competing with SDG&E was further complicated by the CPUC's adoption of a Sempra-wide gas transportation rate in 2000. Under this rate method, all EG customers in southern California pay the same intrastate transportation rate. At $0.027 per therm ($0.27 per Dth), the current rate for the largest EG customers (with annual usage over 3 million therms) is $0.012 per them ($0.12 per Dth) less than SDG&E's stand-alone cost of serving power plant customers. The rate is also less than the sum of the SoCal Gas' wholesale transportation rate for SDG&E ($0.018 per therm ($0.18 per Dth) plus SDG&E's estimated gas transmission rate for Chula Vista of $0.023 per therm ($0.23 per Dth). As a result, before adding any internal capital or operating costs, Chula Vista is projected to lose roughly $0.014 for every therm of gas delivered to South Bay. A shown by Table 8, annual losses are projected to grow substantially over time, increasing from an estimated $1.5 million in 2003 and $7.0 million in 2023. Such losses are unlikely to be offset by property taxes and other revenues from the power plant.

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[84] Prepared Direct Testimony of Mark Newton Lowry on Behalf of San Diego Gas and Electric Company, filed December 20, 2002, revised May 1, 2003. The study can be downloaded from the following link: http://www2.sdge.com/tariff/COS/sdge/pdf/ExhibitSDGE21.pdf.

Table 8
Economics of Serving South Bay Power Plant

	2003	2023
South Bay Gas Usage 000 Therms	113,489	257,544
SDG&E EG Rate $/Therm	$0.027	$0.038
SDG&E Cost 000$	$3,118	$9,769
SoCalGas/SDG&E Rate to C.V. $/Th	$0.041	$0.056
SoCalGas/SDG&E Cost 000$	$4,612	$14,452
Net Profit/(Loss) 1/	($1,495)	($4,683)

1/ Excludes Chula Vista capital or operating costs.

(4) The MEU Study Team's benchmarking analysis of municipal gas utilities in California and other regions of the United States indicates that Chula Vista is unlikely to provide gas delivery service to its residential, commercial/industrial, and power plant customers for less than the average rate of $0.10 per therm these customers pay to SDG&E. The average T&D cost of the two leading California municipal gas systems, Long Beach and Palo Alto, is close to $0.20 per therm. The average T&D rate for the four utilities surveyed by NCI is about $0.15 per Dth. Thus, even assuming a low $0.01 per therm rate to serve the South Bay Power Plant, the average cost of service estimated for Chula Vista ($0.106 per therm) is projected to be five percent higher than SDG&E's current rate. Including the loss of franchise fee payments after municipalization, Chula Vista is projected to lose approximately $1.5 million per year providing gas distribution service in 2003. The loss is projected to rise to $3.6 million in 2010 and $7 million in 2023. Over the 18-year period from 2006 to 2023, the NPV of the total loss is estimated to be $24 million.

(5) As this feasibility analysis reflects, on September 17, 2003, SDG&E filed an application for significant increases in its natural gas rates as part of its Biennial Cost Allocation Proceedings (BCAP). If approved, SDG&E's new gas rates would become effective on January 1, 2005. In the event that SDG&E succeeds in its proposal to increase its gas rates, the MEU Study Team recommends that the City should reexamine the feasibility of providing gas distribution services.

CONCLUSIONS AND RECOMMENDATIONS

V. CONCLUSIONS AND RECOMMENDATIONS

A. Discussion and Comparison of Recommended Options

In adopting Ordinance No. 2835 establishing the City as a Municipal Energy Utility,[85] and Resolution No. 2001-162 adopting the City Energy Strategy,[86] the City of Chula Vista has laid a firm foundation and preserved its options for the development and implementation of energy projects for the benefit of the City and its inhabitants. In furtherance of the City Energy Strategy Plan, the City retained the MEU Study Team to perform a "Municipal Energy Utility Feasibility Analysis" based, in part, upon the results of earlier studies performed for the City by MRW Associates and Science Applications International Corporation.

In conducting this feasibility analysis, the MEU Study Team performed a thorough analysis of the energy markets in California and in the San Diego Gas & Electric Company's service territory and prepared a comparative analysis of the City's opportunities and options to develop and implement the City Energy Strategy. Following the directives of the City's Council and Staff, the MEU Study Team developed a series of conclusions and recommendations, which are summarized below. In conducting this feasibility analysis, the MEU Study Team examined both the markets for electricity and gas and determined the feasibility of developing a Municipal Energy Utility, that would provide both electric and gas service. For the reasons set forth in this Report and summarized below, the MEU Study Team has concluded that it is feasible for the City to develop and implement a municipal electric utility on a phased basis. At the same time, however, the MEU Study Team concluded that it is simply not financially or economically feasible under any scenario for the City to undertake to provide gas service to consumers within the City within the study period, barring a change in the projected natural gas rates for SDG&E. The options examined by the MEU Study Team are discussed separately below, together with the recommendations and conclusions reached with the completion of this feasibility analysis.

B. Electric Service

After an initial screening to identify all MEU options available to the City under applicable State and Federal laws and regulations, the MEU Study Team conducted a detailed economic analysis which included a separate evaluation of three basic municipal electric utility options. These options included: (1) ownership and operation of distribution facilities in newly developing areas within the City (Greenfield development); (2) aggregation of electric loads within the City for purposes of procuring wholesale electricity through a Community Choice Aggregation program (CCA), as provided for in Assembly Bill 117 (2002); and (3) acquisition of the existing SDG&E distribution system within the City boundaries and assumption of SDG&E's distribution

[85] Ordinance No. 2835, June 5, 2001.

[86] Resolution No. 2001.162, May 29, 2001.

operations to serve electric customers within the City (MDU). The MEU Study Team also performed an economic analysis of a combined Greenfield/CCA option. Each of these options are identified as economically feasible for immediate or near-term development.

In addition to the three basic MEU options, the MEU Study Team also identified and evaluated two additional options which would be recommended in the long term only in the event that the City develops a full service electric distribution system. The long-range options which were evaluated and analyzed were (1) the development of a Municipal Utility District (MUD), and/or (2) participation in a Joint Powers Agency (JPA) to broaden the City's energy supply options and take advantage of the economies of scale.

Each of the foregoing options is separately discussed and summarized below.

1. Community Choice Aggregation Programs

The first option analyzed and evaluated by the MEU Study Team is a CCA program pursuant to Assembly Bill 117 (Midgen 200-2 - Chapter 838, Statutes of 2002).

Under the CCA option, the City would procure electric supply for customers of the CCA, and SDG&E would continue to deliver the electricity to end users over the distribution facilities owned and operated by SDG&E. Customers would continue to pay SDG&E at retail rates for transmission and distribution services, but would receive a credit for the costs related to generation and the procurement of electricity that would be provided by the CCA.

The CCA option is complicated somewhat by the fact that the CPUC has not issued final rules and regulations to implement CCA pursuant to Assembly Bill 117. On September 4, 2003, the CPUC issued an order instituting rulemaking (R.03.03.007) which establishes proposed rules for CCA and a schedule for final implementation of the program. On October 2, 2003, the CPUC reissued the proposed Rulemaking under Docket No. R.03-10-003, and an initial prehearing conference and workshop have been held. At this juncture, the CPUC has not set a date for final implementation of the CCA rules and regulations.

If the City elects to pursue implementation of a CCA program, the MEU Study Team believes it is important for the City to continue to be at the table representing its interest in ongoing CPUC proceedings to establish the costs, credit, rules and protocols that will ultimately decide CCA program cost-effectiveness and feasibility. By actively participating in related CPUC proceedings, hearings and workshops, the City can best advance its interests.

In preparing the financial pro forma for a CCA program, the MEU Study Team did a thorough analysis of: (1) SDG&E's forecasted rates (including potential exit fees and lost franchise revenues); (2) CCA energy or commodity costs (including generation ownership, power purchase contracts, renewable energy contracts and spot-market purchases; (3) CAISO charges; and (4) operation and maintenance costs. In this evaluation, the MEU Study Team assessed the cost and benefits of the CCA program based on two energy strategies. Under the first strategy, the City would procure all of its energy requirements in the wholesale energy market by executing power contracts with various power suppliers at fixed prices for medium and short terms (Contracts Supply Strategy). In the second strategy, it was assumed that the City would install its own generating facilities or take an ownership position in a power generation facility developed by another entity (Generation Supply Strategy). The Generation Supply Strategy is based upon City ownership of, or entitlement to, 130 MW of new combined cycle gas turbine power plant capacity. The financial pro forma analysis compares the total costs of each option with the total costs of continuing to take retail utility service from SDG&E.

Under the Contracts Supply Strategy, cost savings are projected to occur in the years 2006-10. Projected SDG&E rate reductions in 2011 resulting from the expiration of DWR power purchase contracts eliminate the savings in the years 2011 through 2014. At that time, annual increases in SDG&E's rates are projected to provide persistent savings to the City through the study period. Savings begin at $6.3 million/year in 2006 and increase to $11 million/year in 2023.

The CCA program with a Generation Supply Strategy promises to optimize the City's revenues and savings to its customers. If Chula Vista secures 130 MW of generation capacity, the MEU Study Team projects savings to begin at $13.3 million/year in 2006 and grow to $21.3 million/year in 2023. Here again, savings will be reduced significantly in the years 2011-2014 due to the expiration of SDG&E's DWR contracts and increase as SDG&E's wholesale rates are increased.

The major benefit available under the CCA program is that, under this option, the City could begin purchasing electric energy and supplying it to its retail customers without the need to purchase the SDG&E electric distribution system. It would also provide a generation portfolio and the infrastructure and experience necessary if the City later elects to establish an MDU and acquire and operate the electric distribution system within the City.

2. Greenfield Development

Under the Greenfield utility structure, the City of Chula Vista, in collaboration with developers, would build and own the new electric distribution facilities in selected developing areas. In those undeveloped areas in which SDG&E has not installed electric distribution facilities, the City may exercise its right to begin to provide electric service and to own and operate the electric distribution system. Using these new distribution facilities, the City can serve end use customers located in the newly developed area with power it procures at wholesale from suppliers under power purchase contracts.

In performing the economic study of Greenfield development, the MEU Study Team worked with the City Planning Division Staff to identify prospective new development areas. Based upon planned land use in these areas, the MEU Study Team modeled the site specific energy requirements in each of six areas. The areas found to be especially adaptable to Greenfield development were the Mid-Bayfront area, the Eastlake/Otay Ranch area and the Sunbow Industrial Planning area.

The Greenfield utility option would require that the City take wholesale transmission service from SDG&E and the CAISO and to develop the infrastructure to interconnect the City's distribution facilities with SDG&E at a distribution voltage. SDG&E would provide wholesale transmission service to the City under SDG&E's WDAT.

The MEU Study Team projected the cost of taking wholesale distribution service under SDG&E's WDAT and developed projections for the initial cost of construction, the distribution infrastructure necessary to serve the Greenfield areas. The MEU Study Team then developed a projected electric supply portfolio, including long and short-term power purchase contracts and renewable energy contracts. The study showed that a stand-alone Greenfield utility was not of sufficient size to support the development of an internal generation project by the City. Therefore, the projected power supply for the Greenfield utility is 100% contract based.

Based upon the economic analyses, the MEU Study Team concluded that a Greenfield utility could commence service in 2006, but would suffer some losses until 2012. Beginning in 2012, the MEU Study Team projected persistent savings through the end of the study period (2023) due to the addition of a larger number of electricity users and the addition of large commercial and industrial loads. Accordingly, the MEU Study Team has concluded that the development of Greenfield Projects within the City is both economically feasible and desirable and recommends that the City immediately implement plans to develop Greenfield projects.

In addition to the economic benefits to be derived over the study period, the development and operation of Greenfield projects also produces other non-financial benefits to the City. Importantly, the operation of the City's Greenfields projects will put the City into the utility business, provide City personnel with experience in operating an electric utility, and provide the City with the beginnings of an electric distribution infrastructure. Moreover, as discussed below, the Greenfield option can be readily combined with a CCA program to optimize savings to customers within the City and is easily absorbed as part of a municipal distribution system if the City later decides to form an MDU and acquire and operate the electric distribution facilities within the City boundaries.

3. Combined CCA and Greenfield Development

The detailed economic and financial analysis performed by the MEU Study Team demonstrates that the City can obtain the greatest potential benefit in the short term by forming a CCA and simultaneously pursuing Greenfield project opportunities. Under the most beneficial option, the City would build or otherwise gain entitlement to a generation project (130 MW) within the City to supply the combined CCA/Greenfield loads. The CCA program would give the City the operational scale required to effectively source electricity for the CCA and Greenfield customers and successfully compete with the electric supply portfolio of SDG&E.

In implementing the combination of CCA and Greenfield projects, the City can capture the benefits of CCA in areas where there is presently an SDG&E distribution infrastructure and realize commensurate savings on the electric energy component for Greenfield areas, thus significantly increasing the cost effectiveness of the Greenfield projects. Administration of the combined CCA and Greenfield Projects would be consolidated under a single City Staff (Municipal Electric Department).

In the combined CCA/Greenfield scenario, the City would implement a City-wide CCA program concurrent with efforts to begin distribution utility operations in Greenfield development areas. The City would supply electricity to all electric customers within the City and distribute electricity to electric customers within the Greenfield development areas.

For non-Greenfield areas, the City would produce or provide electric supply for its CCA customers and SDG&E would continue to deliver the electricity to end-use customers over its distribution facilities. The City's CCA customers would pay SDG&E the retail rate for non-generation (transmission and distribution) services as they do today and would receive a generation credit for electric power provided by the City under the CCA program. SDG&E would continue to perform metering and billing services for end-use CCA customers.

For Greenfield areas, the City would take wholesale transmission service from SDG&E or the CAISO, and its customers in Greenfield development areas would no longer pay SDG&E retail rates. The City would take transmission service from SDG&E under its WDAT for the Greenfield development loads at transmission rates to be determined based on the SDG&E facilities actually used to provide this service. Consumers in the Greenfield areas would receive a power credit for electric power purchased or produced by the City.

As discussed above, the implementation of a CCA program is complicated by the fact that the CPUC has not issued rules and regulations for implementation of CCA programs. This complication would also be applicable to the CCA/Greenfield combination and may delay the immediate implementation of the CCA option.

Based on the financial pro forma performed by the MEU Study Team, the combined CCA/Greenfield utility option, using in-City generation would produce savings amounting to $14.9 million in 2006 and increase to $31.7 million in 2023 (again with significant reductions in savings in the 2011-2014 time frame).

The MEU Study Team strongly recommends that the City implement the combined CCA/Greenfield utility option in the immediate future. The MEU Study Team estimates that a CCA program would be operational by mid-2005 (assuming that the CPUC issues final rules and regulations by mid-2004). With respect to Greenfield development, the MEU Study Team estimates that the initial Greenfield project could be implemented in a 15 to 20 month time frame depending upon the construction schedule and building occupancy within the designated Greenfield areas. Thus, a combined CCA/Greenfield operation could be implemented at least by 2006.

4. Municipal Distribution Utility

Under the Municipal Distribution Utility (MDU) option, the City would acquire, by negotiation or through the exercise of the power of eminent domain, the electric distribution facilities of SDG&E within the City's boundaries. The City's MDU would take wholesale transmission service from SDG&E and the CAISO and its customers would no longer pay the SDG&E retail rates.

Once the MDU is established, the MDU would take wholesale transmission service from SDG&E under SDG&E's WDAT which defines the applicable charges and terms and conditions of transmission service.

SDG&E would be required to perform a study to determine the cost of any reconfiguration of the SDG&E system in order to separate and interconnect the MDU system with the remaining SDG&E system. The Federal Energy Regulatory Commission would, in the event of a dispute, determine the terms and conditions of the interconnection of the MDU with the SDG&E transmission system and the interconnection and related costs would be directly assigned to the MDU.

If the MDU and SDG&E cannot agree on the terms and conditions of the acquisition, including the pricing of the distribution system, the City will be required to initiate and prosecute the condemnation of SDG&E's distribution system and allow the condemnation court (or, alternatively, at the discretion of the City the CPUC) to determine the value of the facilities acquired and any related severance costs.

Once established, the MDU would become a full service electric distribution utility and commence serving some 86,652 retail electric customers with a peak electric load of approximately 147 megawatts.

The MDU option would require a substantial investment in distribution infrastructure to distribute electric power to the customers of the City's MDU, including distribution substations, primary distribution transformers, primary distribution wires and poles, final line transformers, secondary distribution feeders, and meters.

For purposes of this feasibility analysis, the MEU Study Team has, based on data available from SDG&E, the City's tax records, and the CPUC, estimated the value of the SDG&E distribution system at $170 million. Using this acquisition cost figure, the MEU Study Team estimated the combined system acquisition and start-up costs (including distribution facilities, customer service call center, billing equipment and service vehicles) to be $185 million.

In assessing the feasibility of the MDU option, the MEU Study Team has assumed that the City would either (1) acquire at least 130 MW of combined cycle gas turbine capacity (Generation Supply Strategy) or procure all electric requirements under power supply contracts and renewable energy contracts (Contracts Supply Strategy). As shown in the results of the study, the MDU operation would benefit by ownership of generation within the City as opposed to purchasing all requirements under contract. Production costs of a new combined cycle gas turbine are projected to be below the market clearing prices in the California market. Moreover, by locating and owning generation within the City boundaries, the MDU would avoid paying high transmission costs, including transmission congestion charges and other charges assessed by the CAISO.

In addition to the capital costs necessary to acquire the SDG&E distribution system and establish necessary interconnections and bulk power supply costs, the MEU Study Team estimated the distribution operations and maintenance costs and has taken into consideration the required payment for "exit fees" and other non-bypassable charges mandated by legislation and related CPUC orders and any applicable Federal stranded costs which may be required under FERC rules or regulations. The MEU Study Team has also factored in the loss of franchise and/or tax revenues. As set out in more detail in the technical appendices, the actual amount of any applicable exit fees or cost responsibility surcharges will vary over time and depending on the outcome of several pending proceedings before the CPUC. To the extent that exit fees are leveled out over time, the costs will be borne by departing customers for a longer period of time. In the event that the fees are charged at higher rates in the beginning, they will be paid off sooner, and therefore no longer a factor in considering longer term strategies.

Based upon the pro forma financial analysis performed by the MEU Study Team, a City-owned MDU would, under the MDU Generation Supply Strategy (i.e., with at least 130 MW of in-City generation) realize $12.3 million/year in savings in 2006 and increasing to $28.7 million in 2023. Savings would be substantially reduced in the 2011-2014 time frame due to the expiration of SDG&E's obligations under its contracts with DWR. Savings over the study period (2008-23) would amount to approximately $329 million yielding an NPV of $109 million.

Under an MDU Contracts Supply Strategy (i.e., under which the Chula Vista MDU purchases all electric power requirements in the market and pays related transmission costs), the MDU would suffer losses in the first eleven years and realize only modest savings in the period from 2017 through 2023. Based upon the pro forma results, the MEU Study Team has concluded that an MDU that relies exclusively on market purchases of wholesale electricity to serve the entire load requirements of its customers would not be a cost-effective option for the City in the near term.

Under an MDU Generation Supply Strategy, based upon the positive results of the pro forma financial studies and the other major benefits, which will accrue from the implementation of the MDU option, the MEU Study Team believes that it is feasible, from both an economic and operational standpoint, for the City to form and operate an MDU by acquiring the distribution assets of SDG&E. In coming to this conclusion, the MEU Study Team recognizes that, because of the substantial capital investment required to acquire the distribution system, generation facilities and to defray the start-up expenses for an MDU, the potential value of benefits to the City is less favorable than the CCA/Greenfield option with a Generation Supply Strategy. At the same time, the MEU Study Team is of the opinion that, in the long run, the ownership of the electric distribution system would allow the City to serve all electric customers within the City at rates substantially below the current and projected rates of SDG&E and permit the city to build asset value in the distribution system. The MEU Study Team has also given substantial weight to the non-financial benefits to be realized by public ownership of the distribution system, including local control of rates and service, discretion in the application of savings or benefits, and independence from SDG&E and the owner/operators of the transmission grid.

Given the additional planning and study requirements needed to implement the MDU option, together with the procedural steps which must be followed under the Eminent Domain Law, the MEU Study Team recommends that the City defer implementation of the MDU option until the 2008-10 time frame and re-evaluate the option based on circumstances existing at that time. Assuming that the City proceeds to develop the CCA and Greenfield options in the meantime, the City will have an MEU infrastructure, customer base, generation facilities and several years of operating experience before needing to make the critical decision of potentially acquiring the distribution system of SDG&E. In the event that CCA appears to be uneconomic once the CPUC has issued its final rulemaking decisions, the MEU Study Team would recommend that the City accelerate its consideration of the MDU option.

5. Joint Powers Agency and Municipal Utility District Options

As discussed in Section IV. G of this Report, once the City of Chula Vista establishes a full service MDU and acquires the electric distribution facilities of SDG&E, two other long-range options will be available to the City's MDU. The City, through its MDU may be able to participate in an existing JPA, or form, in partnership with another community, unincorporated territory, or public utility entity, an MDU. These options are discussed briefly below.

a. Joint Powers Agency

Under California law, a municipal electric utility, in combination with one or more other municipal electric utilities (including other publicly-owned electric systems, an irrigation district, public utility district or municipal utility district) may form a JPA to provide either generation resources, transmission services, or both.

Currently, there are a number of joint action agencies operating in the State of California including the Southern California Public Power Agency (SCPPA), the Northern California Power Agency (NCPA), M-S-R Public Power Agency (M-S-R) and the Transmission Agency of Northern California (TANC). Of these, based on geographic considerations, SCPPA is the only JPA that might offer the Chula Vista MDU any benefits in the form of generation or transmission resources in the foreseeable future. Because JPAs plan and develop transmission and generation resources to meet the existing and prospective needs of its members, it is unlikely that SCPPA would be in the position to provide any transmission or generation benefits to the Chula Vista MDU from existing projects and contracts, all of which are dedicated to the needs of existing members. The Chula Vista MDU could, however, apply for membership in SCPPA for the purpose of participating in any future generation or transmission projects. Moreover, from time to time, the Chula Vista MDU might find opportunities to acquire surplus capacity from the existing members of SCPPA on a priority basis once it becomes a member of the JPA.

It is premature at this juncture to attempt to identify or quantify any specific benefits that the Chula Vista MDU might realize from membership in a JPA. This is, however, an important option which should be explored once Chula Vista establishes a full service electric distribution system.

Once the Chula Vista MDU becomes a member of an operating JPA, it will be able to take advantage of possible aggregation of a larger load for resource procurement purposes and, with the addition of power supply partners, the Chula Vista MDU could share or spread the risks of operating the MDU. Membership in a JPA might, in turn, lead to possible reductions in operation and maintenance costs through cost sharing arrangements with other members of the JPA.

In the near term, there is no need for the City to take any action related to membership in a JPA. Once it is in the business of providing full service electric distribution service, however, the City should examine all options open to forming or joining a JPA.

b. Municipal Utility District

Under California law, a municipality is permitted to join or form an MUD for the purpose of developing generation and transmission resources and otherwise conducting utility operations on a District-wide basis. Interestingly, it is not required that the members of an MUD be located contiguously. Under these circumstances, Chula

Vista, once it determines to provide full electric utility distribution service, could form an MUD with another community, unincorporated area or public power entity located in other parts of the State.

At present, there are no MUDs operating in Southern California. There are, however, some fifteen other municipal electric systems operating in Southern California and a number of other cities are attempting to form municipal utilities within their boundaries.

Like a JPA, the MUD model would allow the City MDU to spread risk, take advantage of the economies of scale and combine electric loads to the end that it can secure more competitively priced power by combining the needs of more residential and commercial and industrial loads, thereby lowering the price of utility services, on a per unit basis, for all customers within the boundaries of the MUD.

It is premature at this juncture to speculate on the potential for partners to join with Chula Vista in forming an MUD. The options are almost endless inasmuch as the City can join with any other community or unincorporated territory in forming an MUD. It is not a prerequisite that the community or unincorporated territory have an existing municipal electric system and there is no requirement that the participants in the MUD be contiguous. Suffice it to say that, once Chula Vista elects to provide full electric utility distribution services, it may want to identify opportunities to joint venture the utility operation with another community or unincorporated territory under an MUD structure.

C. Roll Out Strategy

As part of this feasibility analysis, the MEU Study Team has provided a detailed listing of the major and critical steps necessary to implement each of the recommended MEU options. The MEU Study Team has also provided a Gantt Chart showing the time-line requirements for each major step or task necessary from the initiation of the process to operations. (*See* Gantt Charts below and in Appendix C, Section V at 130-32).

1. CCA – Implementation Schedule

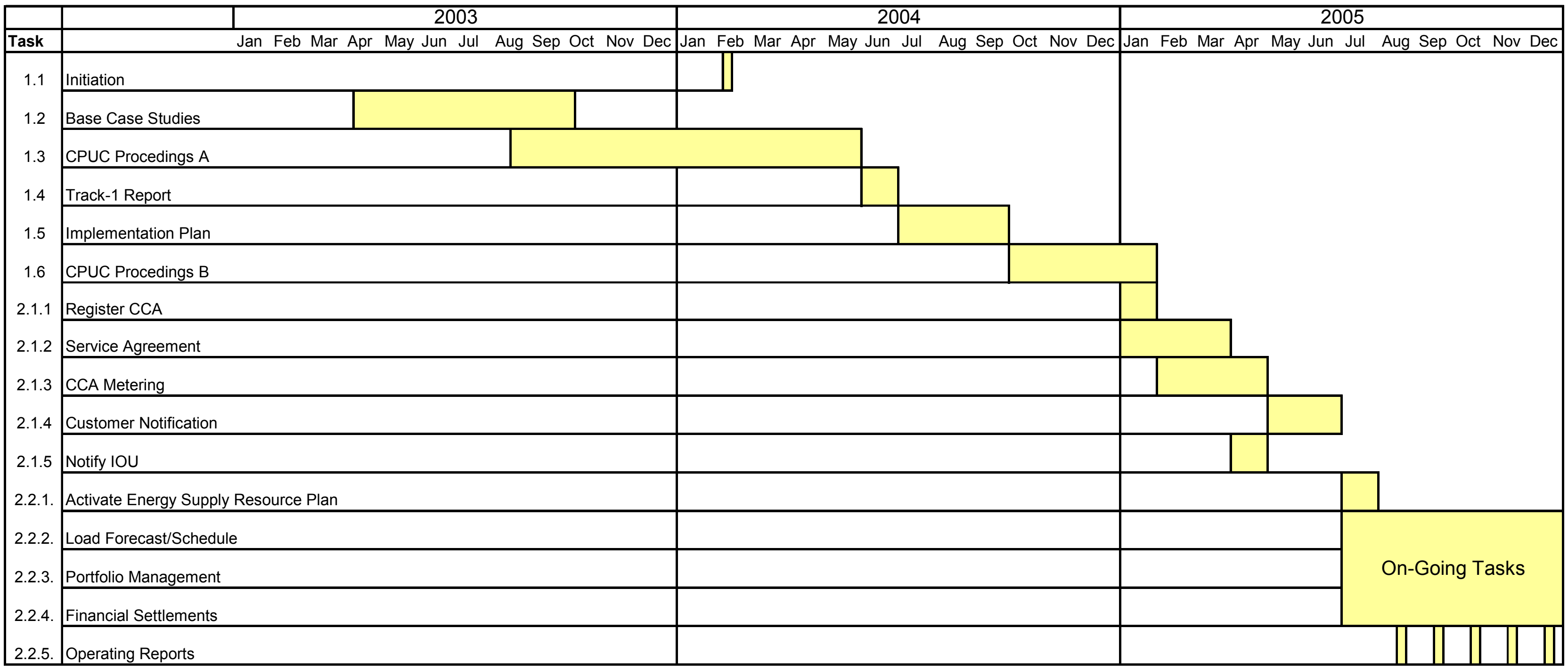
The MEU Study Team recommends a two-track approach to evaluate and implement a CCA project. Within Track One the following tasks are required immediately: (1) conduct an orientation session for Elected Officials and Staff on this option including a review of this feasibility analysis; (2) continue active participation in the CPUC's proceedings and workshops for the development of costs, credit rules and regulations; (3) update the feasibility analysis with information from the CPUC proceedings; and (4) develop the CCA Implementation Plan, adopt the Implementation Plan at a duly noticed public hearing, pass an Ordinance to implement CCA per the

Implementation Plan and file the Implementation Plan with the CPUC by July 2004.[87] Under Track One, the MEU Study Team anticipates that the CPUC approval of the City's Implementation Plan would take between four to seven months.

Assuming CPUC approval of the City's CCA Implementation Plan by January 2005, the following tasks would be initiated simultaneously within Track Two: (a) the City would execute a Service Agreement with SDG&E; (b) complete development of CCA metering facilities; and (c) complete customer notification regarding opt-out provisions. Between July 2005 and January 2006 the following iterative and on-going activities should be conducted by the City: (1) activate Energy Supply Resource Plan; (2) address Load Forecast and Optimize Scheduling; (3) manage supply portfolio and risk management (4) process financial settlements; and (5) produce operating statements and reports. Under this schedule and based on these assumptions, the MEU Study Team anticipates that a CCA project could be operational by early 2006. Please see Section IV.C.6 at 58-60 for more detail on this Implementation Schedule.

[87] Although the CPUC has not approved rules for the implementation of the CCA program, the draft rules and CPUC precedent indicate that parties have submitted applications for the CCA program.

CCA Implementation Schedule

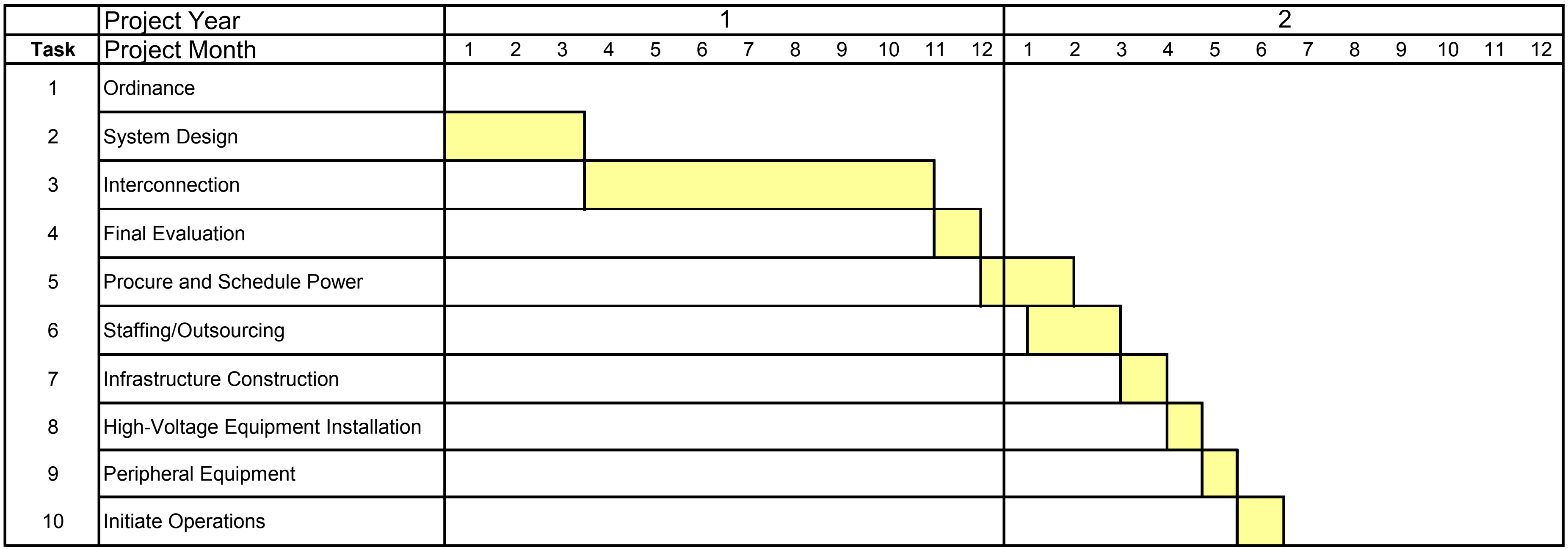


2. Greenfield – Implementation Schedule

Recognizing that the City has previously passed an ordinance to form a municipal utility and, working back from the date that occupancy of the Greenfield areas would be initiated (as early as July 2005), the MEU Study Team recommends that the following steps be taken by the City to implement the Greenfield option: (1) consult with electric distribution design firms and developers to design and specify system requirements for the Greenfield Project, initiate in January 2004 and complete by April 2004; (2) following the development of the design and system requirements, the City would need to determine the interconnection requirements, which includes an assessment of technical requirements and costs to achieve interconnection of the distribution system, initiate in April 2004 and complete no later than mid-November 2004; (3) evaluate and assess projected loads, costs and benefits, initiate in November 2004 and complete by mid-December 2004; 4) based upon the final evaluation of load studies and forecasts, the City would need to tailor and implement a resource plan and schedule power and update power delivery schedules; (5) the City would initiate a human resource plan, in December 2004 and complete staffing by February 2005; (6) developers would complete infrastructure construction (trenches, conduits, vaults and transformer pads) in the March to April 2005 time frame; (7) high voltage contractors would install conductors, transformers, service drops and metering in April 2005; (8) contractors would install streetlights, traffic signals and landscape irrigation facilities (peripheral equipment) by Mid May 2005; and (9) utility service could be provided between mid-May and mid-June 2005 or be scheduled to coincide with an occupancy. Please see Section IV.D.6 at 77-79 for more detail on this Implementation Schedule.

Greenfield Implementation Schedule

Greenfield Utility Development



3. CCA/Greenfield – Implementation Schedule

The implementation schedule for the CCA/Greenfield entails utilizing the major and critical steps identified in the implementation schedules for CCA and Greenfield options and combining them. The major and critical steps and timelines would remain unchanged.

4. MDU – Implementation Schedule

If the City elects to form an MDU, the MEU Study Team has identified the following major and critical steps: (1) During the first year after electing to pursue the MDU option, the City should complete the feasibility and implementation plan, which includes: (a) Distribution System Survey and Valuation, (b) Severance Plan and Cost Study, (c) Energy Resource Plan, (d) Human Resource Plan, (e) Facilities Plan, (f) Pro Forma Update, (g) Finance Plan, (h) Governance Plan, and (i) Implementation Plan. (2) by the end of the first year, establish public interest; (3) begin the condemnation process: (a) offer to purchase the distribution facilities of SDG&E, (b) public hearing on finding of public interest and necessity, (c) adopt Resolution of Necessity to condemn property, (d) second and final offer of purchase to be extended to SDG&E, (e) judicial review of Resolution of Necessity, (f) conduct the condemnation proceeding; and (4) execute Implementation Plan once condemnation proceedings have been completed and an Order for Possession has been entered by a court of competent jurisdiction. If the City elects to implement the MDU option in the 2010 time frame, after the establishment of the Combined CCA/Greenfield option, as recommended by the MEU Study Team, the City would commence the MDU Planning and Implementation elements in mid-2008. Please see Section IV.F.6 at 127-131 for more detail on this Implementation Schedule.

MDU Implementation Schedule